DCP Midstream Partners, LP
Form 10-K
March 14, 2007

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

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended: December 31, 2006

or

o **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: 001-32678

DCP MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	**03-0567133**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
370 17th Street, Suite 2775 Denver, Colorado	**80202**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code: 303-633-2900

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 Partner 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 Exchange Act of 1934, or the Act. Yes o No þ

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 o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Act 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 þ No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (see definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Act) (Check one):

Large accelerated filer o Accelerated filer þ Non-accelerated filer o

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant on June 30, 2006, was approximately $288,920,000. The aggregate market value was computed by reference to the last sale price of the registrant s common units on the New York Stock Exchange on June 30, 2006.

As of March 12, 2007, there were outstanding 10,357,143 common limited partner units, 200,312 Class C units, and 7,142,857 subordinated units.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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PART IV.

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GLOSSARY OF TERMS

The following is a list of certain industry terms used throughout this report:

Bbls	barrels
Bbls/d	barrels per day
Btu	British thermal unit, a measurement of energy
Fractionation	the process by which natural gas liquids are separated into individual components
Frac spread	price differences, measured in energy units, between equivalent amounts of natural gas and NGLs
MBbls	one thousand barrels
MBbls/d	one thousand barrels per day
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
MMBtu	one million British thermal units, a measurement of energy
NGLs	natural gas liquids
Tcf	one trillion cubic feet
Throughput	the volume of product transported or passing through a pipeline or other facility

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our 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 within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as may, could, project, believe, anticipate, expect, estimate, potential, pl other similar words.

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

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

- the level and success of natural gas drilling around our assets, and our ability to connect supplies to our gathering and processing systems in light of competition;

- our ability to grow through acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;

- our ability to access the debt and equity markets, which will depend on general market conditions, interest rates and our ability to effectively hedge such rates with derivative financial instruments to limit a portion of the adverse effects of potential changes in interest rates, and the credit ratings for our debt obligations;

- the extent of changes in commodity prices, our ability to effectively hedge to limit a portion of the adverse impact of potential changes in prices through derivative financial instruments, and the potential impact of price on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;

- our ability to purchase propane from our principal suppliers for our wholesale propane logistics business;

- our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required building, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for supplies;

- the creditworthiness of counterparties to our transactions;

- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and our and third-party-owned infrastructure;

- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the increased regulation of our industry;

- industry changes, including the impact of consolidations, alternative energy sources, technological advances and changes in competition;

the amount of collateral required to be posted from time to time in our transactions; and

general economic, market and business conditions.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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Item 1. *Business*

Our Partnership

DCP Midstream Partners, LP along with its consolidated subsidiaries, or we, us, our, or the partnership, is a Delaware limited partnership formed by DCP Midstream, LLC (formerly Duke Energy Field Services, LLC) to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are currently engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas, the business of producing, transporting and selling propane and other natural gas liquids, or NGLs, and the business of storing propane. Supported by our relationship with DCP Midstream, LLC and its parents, Spectra Energy Corp (the natural gas business which was spun off from Duke Energy Corporation, or Duke Energy, effective January 2, 2007), which we refer to as Spectra Energy, and ConocoPhillips, we intend to acquire and construct additional assets and we have a management team dedicated to executing our growth strategy.

Our operations are organized into three business segments, Natural Gas Services, Wholesale Propane Logistics and NGL Logistics.

Our Natural Gas Services segment is comprised of our North Louisiana system, which is an integrated pipeline system located in northern Louisiana and southern Arkansas that gathers, compresses, treats, processes, transports and sells natural gas, and that sells NGLs. This system consists of the following:

- the Minden processing plant and gathering system, which includes a cryogenic natural gas processing plant supplied by approximately 700 miles of natural gas gathering pipelines, connected to approximately 460 receipt points, with throughput and processing capacity of approximately 115 million cubic feet per day, or MMcf/d;

- the Ada processing plant and gathering system, which includes a refrigeration natural gas processing plant supplied by approximately 130 miles of natural gas gathering pipelines, connected to approximately 210 receipt points, with throughput capacity of approximately 80 MMcf/d; and

- the Pelico Pipeline, LLC system, or Pelico system, an approximately 600-mile intrastate natural gas gathering and transportation pipeline with throughput capacity of approximately 250 MMcf/d and connections to the Minden and Ada processing plants and approximately 450 other receipt points. The Pelico system delivers natural gas to multiple interstate and intrastate pipelines, as well as directly to industrial and utility end-use markets.

Our Wholesale Propane Logistics segment, which we acquired in November 2006, consists of the following:

- six owned propane rail terminals located in the Midwest and northeastern United States, with aggregate storage capacity of 25 thousand barrels, or MBbls;

- one leased propane marine terminal located in Providence, Rhode Island, with storage capacity of 450 MBbls;

- one propane pipeline terminal that is under construction in Midland, Pennsylvania; and

- access to several open access pipeline terminals.

Our NGL Logistics segment consists of the following:

- our Seabreeze pipeline, an approximately 68-mile intrastate NGL pipeline in Texas with throughput capacity of 33 thousand barrels per day, or MBbls/d;

- our Wilbreeze pipeline, the construction of which was completed in December 2006, an approximately 39-mile intrastate NGL pipeline in Texas, which connects a DCP Midstream, LLC gas processing plant to the Seabreeze pipeline, with throughput capacity of 11 MBbls/d; and

- our 45% interest in the Black Lake Pipe Line Company, or Black Lake, the owner of an approximately 317-mile interstate NGL pipeline in Louisiana and Texas with throughput capacity of 40 MBbls/d.

For additional information on our segments, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and Note 18 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

Our Business Strategies

Our primary business objective is to increase our cash distribution per unit over time. We intend to accomplish this objective by executing the following business strategies:

Optimize: maximize the profitability of existing assets. We intend to optimize the profitability of our existing assets by adding new volumes of natural gas, propane and NGLs, and undertaking additional initiatives to enhance utilization and improve operating efficiencies. Our natural gas assets, and propane and NGL pipelines, have excess capacity, which allows us to connect new supplies of natural gas, propane and NGLs at minimal incremental cost.

Build: capitalize on organic expansion opportunities. We continually evaluate economically attractive organic expansion opportunities to construct new midstream systems in new or existing operating areas. For example, we believe there are opportunities to expand our North Louisiana system to transport increased volumes of natural gas produced in east Texas to premium markets and interstate pipeline connections on the eastern end of our North Louisiana system.

Acquire: pursue strategic and accretive acquisitions. We plan to pursue strategic and accretive acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and geographic areas of operation. In light of the recent industry trend of large energy companies divesting their midstream assets, we believe there will continue to be acquisition opportunities. We intend to pursue acquisition opportunities both independently and jointly with DCP Midstream, LLC and its parents, Spectra Energy and ConocoPhillips, and we may also acquire assets directly from them, which we believe will provide us with a broader array of growth opportunities than those available to many of our competitors.

Our Competitive Strengths

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

Affiliation with DCP Midstream, LLC and its parents. Our relationship with DCP Midstream, LLC and its parents, Spectra Energy and ConocoPhillips, may provide us with significant business opportunities. DCP Midstream, LLC is one of the largest gatherers of natural gas (based on wellhead volume), one of the largest producers of NGLs and one of the largest marketers of NGLs in North America. Our relationship with DCP Midstream, LLC, Spectra Energy and ConocoPhillips also provides us with access to a significant pool of management talent. We believe our strong relationships throughout the energy industry, including with major producers of natural gas and NGLs in the United States, will help facilitate implementation of our strategies. Additionally, we believe DCP Midstream, LLC has established a reputation in the midstream business as a reliable and cost-effective supplier of services to our customers, and has a track record of safe and efficient operation of our facilities.

Strategically located assets. We own and operate one of the largest integrated natural gas gathering, compression, treating, processing and transportation systems in northern Louisiana, an active natural gas producing area. This system is also well positioned. We believe there are opportunities to expand this system to transport increased volumes of natural gas, from east Texas and west Louisiana, to premium markets on the eastern end of our North Louisiana system, and to interconnections with major interstate natural gas pipelines that transport natural gas to consumer markets in the eastern and northeastern United States. Our NGL pipelines are also strategically located to transport NGLs from plants that process natural gas produced in Texas and northern Louisiana to large fractionation facilities, a petrochemical plant and an underground NGL storage facility along the Gulf Coast.

Stable cash flows. Our operations consist of a favorable mix of fee-based and margin-based services, which together with our hedging activities, generate relatively stable cash flows. While our percentage-of-proceeds gathering and processing contracts subject us to commodity price risk, we have hedged a significant portion of our natural gas and NGL commodity price risk related to these arrangements through 2010. As part of our gathering operations, we recover and sell condensate. We have hedged a significant portion of our expected condensate commodity price risk relating to our natural gas gathering operations through 2011. For additional information regarding our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk Hedging Strategies.

Integrated package of midstream services. We provide an integrated package of services to natural gas producers, including natural gas gathering, compression, treating, processing, transportation and sales, and NGL transportation and sales. We believe our ability to provide all of these services gives us an advantage in competing for new supplies of natural gas because we can provide substantially all of the services producers, marketers and others require to move natural gas and NGLs from wellhead to market on a cost-effective basis.

Comprehensive propane logistics systems. We have multiple propane supply sources and terminal locations for wholesale propane delivery. We believe our ability to purchase large volumes of propane supply and transport such supply for resale or storage allows us to provide our customers with reliable deliveries of propane during periods of tight supply. These capabilities also allow us to moderate the effects of commodity price volatility and reduce significant fluctuations in our sales volumes.

Experienced management team. Our senior management team and board of directors includes some of the most senior officers of DCP Midstream, LLC and former senior officers from other energy companies who have extensive experience in the midstream industry. Our management team has a proven track record of enhancing value through the acquisition, optimization and integration of midstream assets.

Our Relationship with DCP Midstream, LLC and its Parents

One of our principal attributes is our relationship with DCP Midstream, LLC and its parents, Spectra Energy and ConocoPhillips. DCP Midstream, LLC commenced operations in 2000 following the contribution to it of the combined North American midstream natural gas gathering, processing and marketing and NGL businesses of Duke Energy and Phillips Petroleum Company (prior to its merger with Conoco Inc.). Currently, DCP Midstream, LLC is owned 50% by Spectra Energy and 50% by ConocoPhillips.

DCP Midstream, LLC intends to use us as an important growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets. In November 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC, and in October 2006, we announced that DCP Midstream, LLC had committed to contribute assets to us in exchange for partnership units and cash valued at approximately $250.0 million. The transaction is targeted for the second quarter of 2007. Identification of the specific assets and the related purchase price, along with the other terms of any specific transaction between DCP Midstream, LLC and us, are subject to the approval of the boards of directors of both us and DCP Midstream, LLC, as well as the special committee of our board of directors. We expect to have future opportunities to make other acquisitions directly from DCP Midstream, LLC; however, we cannot say with any certainty which, if any, of these acquisitions may be made available to us, or if we will choose to pursue any such opportunity. In addition, through our relationship with DCP Midstream, LLC and its parents, we expect to have access to a significant pool of management talent, strong commercial relationships throughout the energy industry and DCP Midstream, LLC s broad operational, commercial, technical, risk management and administrative infrastructure.

DCP Midstream, LLC has a significant interest in our partnership through its ownership of a 2% general partner interest in us, all of our incentive distribution rights and a 40.7% limited partner interest in us. We have entered into an omnibus agreement, or the Omnibus Agreement, with DCP Midstream, LLC and some of its affiliates that governs our relationship with them regarding certain reimbursement and indemnification matters.

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While our relationship with DCP Midstream, LLC and its parents is a significant attribute, it is also a source of potential conflicts. For example, DCP Midstream, LLC, Spectra Energy, ConocoPhillips or their affiliates are not restricted from competing with us. Each of them may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Natural Gas and NGLs Overview

The midstream natural gas industry is the link between exploration and production of natural gas and the delivery of its components to end-use markets, and consists of the gathering, compression, treating, processing, transportation and selling of natural gas, and the production, transportation and selling of NGLs.

Natural Gas Demand and Production

Natural gas is a critical component of energy consumption in the United States. According to the Energy Information Administration, or the EIA, total annual domestic consumption of natural gas is expected to increase from approximately 22.0 trillion cubic feet, or Tcf, in 2005 to approximately 24.0 Tcf in 2010, representing an average annual growth rate of over 1.8% per year. The industrial and electricity generation sectors are the largest users of natural gas in the United States, accounting for approximately 57% of the total natural gas consumed in the United States during 2005. Driven by projections of continued growth in natural gas demand and higher natural gas prices, domestic natural gas production is projected to increase from 18.3 Tcf per year to 19.4 Tcf per year between 2005 and 2010.

Midstream Natural Gas Industry

Once natural gas is produced from wells, producers then seek to deliver the natural gas and its components to end-use markets. The following diagram illustrates the natural gas gathering, processing, fractionation, storage and transportation process, which ultimately results in natural gas and its components being delivered to end-users.

Natural Gas Gathering

The natural gas gathering process begins with the drilling of wells into gas-bearing rock formations. Once the well is completed, the well is connected to a gathering system. Onshore gathering systems generally consist of a network of small diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Natural Gas Compression

Gathering systems are generally operated at design pressures that will maximize the total throughput from all connected wells. Since wells produce at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production from the ground against a higher pressure that exists in the connecting gathering system. Natural gas compression is a mechanical process in which a volume of wellhead gas is compressed to a desired higher pressure, allowing gas to flow into a higher pressure downstream pipeline to be brought to market. Field compression is typically used to lower the pressure of a gathering system to operate at a lower pressure or provide sufficient pressure to deliver gas into a higher pressure downstream pipeline. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise would not be produced.

Natural Gas Processing and Transportation

The principal component of natural gas is methane, but most natural gas also contains varying amounts of NGLs including ethane, propane, normal butane, isobutane and natural gasoline. NGLs have economic value and are utilized as a feedstock in the petrochemical and oil refining industries or directly as heating, engine or industrial fuels. Long-haul natural gas pipelines have specifications as to the maximum NGL content of the gas to be shipped. In order to meet quality standards for long-haul pipeline transportation, natural gas collected through a gathering system may need to be processed to separate hydrocarbon liquids that can have higher values as mixed NGLs from the natural gas. NGLs are typically recovered by cooling the natural gas until the mixed NGLs become separated through condensation. Cryogenic recovery methods are processes where this is accomplished at temperatures lower than minus 150ºF. These methods provide higher NGL recovery yields. After being extracted from natural gas, the mixed NGLs are typically transported via NGL pipelines or trucks to a fractionator for separation of the NGLs into their component parts.

In addition to NGLs, natural gas collected through a gathering system may also contain impurities, such as water, sulfur compounds, nitrogen or helium. As a result, a natural gas processing plant will typically provide ancillary services such as dehydration and condensate separation prior to processing. Dehydration removes water from the natural gas stream, which can form ice when combined with natural gas and cause corrosion when combined with carbon dioxide or hydrogen sulfide. Condensate separation involves the removal of hydrocarbons from the natural gas stream. Once the condensate has been removed, it may be stabilized for transportation away from the processing plant via truck, rail or pipeline. Natural gas with a carbon dioxide or hydrogen sulfide content higher than permitted by pipeline quality standards requires treatment with chemicals called amines at a separate treatment plant prior to processing.

Wholesale Propane Logistics Overview

General

We are engaged in wholesale propane logistics in the Midwest and northeastern United States. Wholesale propane logistics covers the receipt of propane from processing plants, fractionation facilities and crude oil refineries, the transportation of that propane by pipeline, rail or ship to terminals and storage facilities, the storage of propane during low-demand seasons and the delivery of the propane to retail distributors of propane. We engage in all of these wholesale propane logistics services.

Production of Propane

Propane is extracted from natural gas at processing plants, separated from raw mixed NGLs at fractionation facilities or separated from crude oil during the refining process. Most of the propane that is consumed in the United States is produced at processing plants, fractionation facilities and refineries located along the Texas and Louisiana Gulf Coast or in foreign locations, particularly Canada, the North Sea, East Africa and the Middle East.

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Transportation

There are limited processing plants and fractionation facilities in the northeastern United States, and propane production is limited. While significant refinery production exists, propane delivery ratios are limited and refineries sometimes use propane as internal fuel during winter months. As a result, the northeastern United States is an importer of propane, relying almost exclusively on pipeline, marine and rail sources for incoming supplies. Propane is received primarily through pipeline shipments from the Texas and Louisiana Gulf Coast, through rail shipments from western Canada and the Midwest United States, and through marine shipments primarily from the North Sea, East Africa and the Middle East. Propane is normally transported and stored in a liquid state under moderate pressure or refrigeration for ease of handling in shipping and distribution.

Storage

Independent terminal operators and wholesale distributors, such as us, own, lease or have access to propane storage terminals that receive supplies via pipeline, ship or rail. Generally, inventories in the propane storage facilities increase during the spring and summer months for delivery to customers during the fall and winter heating season when demand is typically at its peak.

Delivery

Often, upon receipt of propane at marine, rail and pipeline terminals, product is delivered to customer trucks or is stored in tanks located at the terminals or in off-site bulk storage facilities for future delivery to customers. Most terminals and storage facilities have a tanker truck loading facility commonly referred to as a rack. Often independent retailers will rely on independent trucking companies to pick up product at the rack and transport it to the retailer at its location. Each truck has storage capacity of generally between 9,500 and 12,500 gallons of propane.

Retail uses of propane

Propane is a clean-burning energy source recognized for its transportability and ease of use relative to alternative forms of stand-alone energy sources. Retail propane use falls into three broad categories: (1) residential applications; (2) industrial, commercial and agricultural applications; and (3) other retail applications, including motor fuel sales. Residential customers use propane primarily for home and water heating. Industrial customers use propane primarily as fuel for forklifts, stationary engines, and furnaces, as a cutting gas, in mining operations and in other process applications. Commercial customers, such as restaurants, motels, laundries and commercial buildings, use propane in a variety of applications, including cooking, heating and drying. In the agricultural market, propane is primarily used for tobacco curing, crop drying, poultry brooding and weed control. Other retail uses include motor fuel for cars and trucks, outdoor cooking and other recreational uses. Based upon industry publications, propane accounts for three to four percent of household energy consumption in the United States.

Propane competes with other sources of energy such as electricity, natural gas and heating oil. Although the extension of natural gas pipelines tends to displace propane distribution in areas affected, we believe that new opportunities for propane sales arise as more geographically remote neighborhoods are developed. Many of the new residential growth areas with high demand for propane are located in areas that are difficult or impracticable for natural gas pipelines to reach.

Natural Gas Services Segment

General

Our Natural Gas Services segment consists of the North Louisiana system, which is a large integrated midstream natural gas system that offers the following services:

- gathering;

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- compression;
- treating;
- processing;
- transportation; and
- sales of natural gas, NGLs and condensate.

The system covers ten parishes in northern Louisiana and two counties in southern Arkansas. Through our North Louisiana system, we offer producers and customers wellhead-to-market services. The North Louisiana system has numerous market outlets for the natural gas that we gather, including several intrastate and interstate pipelines, eight major industrial end-users and three major power plants. The system is strategically located to facilitate the transportation of natural gas from eastern Texas and northern Louisiana to pipeline connections linking to markets in the eastern and northeastern areas of the United States.

A map representing the location of the assets that comprise the North Louisiana system is set forth below:

Gathering Systems

The North Louisiana natural gas gathering system has approximately 830 miles of natural gas gathering pipelines, ranging in size from two inches to twelve inches in diameter. The system has aggregate throughput capacity of approximately 195 MMcf/d and average throughput on the system was approximately 148 MMcf/d in 2006. There are 26 compressor stations located within the system, comprised of 60 units with an aggregate of approximately 70,000 horsepower.

The Minden gathering system is an approximately 700-mile natural gas gathering system located in Bossier, Claiborne, Jackson, Lincoln, Ouachita and Webster parishes, Louisiana and two Arkansas counties.

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The system gathers natural gas from producers at approximately 460 receipt points and delivers it for processing to the Minden processing plant. The Minden gathering system also delivers NGLs produced at the Minden processing plant to the Black Lake pipeline. The Minden gathering system has throughput capacity of approximately 115 MMcf/d, and had aggregate throughput of approximately 76 MMcf/d in 2006.

The Ada gathering system is an approximately 130-mile natural gas gathering system located in Bienville and Webster parishes, Louisiana. The system gathers natural gas from producers at approximately 210 receipt points and delivers it for processing to the Ada processing plant. The Ada gathering system has throughput capacity of approximately 80 MMcf/d, and had throughput of approximately 72 MMcf/d in 2006.

Processing Plants

The Minden processing plant is a cryogenic natural gas processing and treating plant located in Webster parish, Louisiana. The Minden processing plant has a design capacity of 115 MMcf/d. In 2006, the Minden processing plant processed approximately 76 MMcf/d of natural gas and produced approximately 5,100 Bbls/d of NGLs. This processing plant has amine treating and ethane recovery and rejection capabilities such that we can recover approximately 80% of the ethane contained in the natural gas stream. In addition, the processing plant is able to reject ethane of effectively 13% when justified by market economics. This processing flexibility enables us to maximize the value of ethane for our customers. In 2002, we upgraded the Minden processing plant to enable greater ethane recovery and rejection capabilities. As part of that project, we reached an agreement with our customers to receive 100% of the realized margin attributable to the incremental value of ethane recovered as an NGL from the natural gas stream when appropriate market conditions exist and until a defined return on the initial investment is reached.

The Ada processing plant is a refrigeration natural gas processing plant located in Bienville parish, Louisiana. The Ada processing plant has a design capacity of 45 MMcf/d. In 2006, the facility processed approximately 54 MMcf/d of natural gas and produced approximately 186 Bbls/d of NGLs.

Transportation System

The Pelico system is an approximately 600-mile intrastate natural gas gathering and transportation pipeline with approximately 250 MMcf/d of capacity and average throughput of approximately 236 MMcf/d in 2006. The Pelico system gathers and transports natural gas that does not require processing from producers in the area at approximately 450 meter locations. Additionally, the Pelico system transports processed gas from the Minden and Ada processing plants and natural gas supplied from third party interstate and intrastate natural gas pipelines. The Pelico system also receives natural gas produced in eastern Texas through its interconnect with other pipelines that transport natural gas from eastern Texas into western Louisiana.

Natural Gas Markets

The North Louisiana system has numerous market outlets for the natural gas that we gather on the system. Our natural gas pipelines connect to the Perryville Market Hub, a natural gas marketing hub that provides connection to four intrastate or interstate pipelines, including pipelines owned by Southern Natural Gas Company, Texas Gas Transmission, LLC, CenterPoint Energy Mississippi River Transmission Corporation and CenterPoint Energy Gas Transmission Company. In addition, our natural gas pipelines also have access to gas that flows through pipelines owned by Texas Eastern Transmission, LP, Crosstex LIG, LLC, Gulf South Pipeline Company, Tennessee Natural Gas Company and Regency Intrastate Gas, LLC. The North Louisiana system is also connected to eight major industrial end-users and makes deliveries to three power plants. Generally, the gas flows from our Minden and Ada gathering systems and Pelico system from west to east toward the industrial and interstate markets with the exception of some industrial end-users located near the central-southern section of the Pelico system. This flow pattern changes somewhat during the summer when utility loads increase deliveries off the same central-southern section of the Pelico system. Our access to numerous market outlets, including interstate pipelines in northeastern Louisiana that deliver natural gas to premium markets on the northeast and east coast, and to several end-users located on our system provides us with the flexibility to deliver our natural gas supply to markets with the most attractive pricing.

The NGLs extracted from the natural gas at the Minden processing plant are delivered to the Black Lake pipeline through our wholly-owned approximately 9-mile Minden NGL pipeline. The NGLs are sold at market index prices to an affiliate of DCP Midstream, LLC and transported to the Mont Belvieu hub via the Black Lake pipeline of which we own a 45% interest. The NGLs extracted from natural gas at the Ada processing plant are sold at market index prices to affiliates and are delivered to the third parties trucks at the tailgate of the plant.

Customers and Contracts

The primary suppliers of natural gas to our North Louisiana system are Anadarko Petroleum Corporation and ConocoPhillips (one of our affiliates), which collectively represented approximately 60% of the 312 MMcf/d of natural gas supplied to this system in 2006 and 48% of the 355 MMcf/d and 328 MMcf/d natural gas supplied to this system in 2005 and 2004, respectively. We actively seek new supplies of natural gas to increase throughput volume and to offset natural declines in the production from connected wells. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, by connecting new wells drilled on dedicated acreage and by obtaining natural gas that has been released from other gathering systems. No individual customer in our Natural Gas Services segment accounted for more than 10% of our total operating revenues for the years ended December 31, 2006, 2005 and 2004.

We currently have approximately 1,100 receipt points on the North Louisiana system receiving natural gas production from individual wells or groups of wells. Approximately 60% of these receipt points are located on our Minden gathering system and our Ada gathering system. The remaining 40% of these receipt points are located on the Pelico system. The natural gas supplied to the North Louisiana system is generally dedicated to us under individually negotiated long-term contracts that provide for the commitment by the producer of all natural gas produced from designated properties. Generally, the initial term of these purchase agreements is for three to five years or, in some cases, the life of the lease. Our Pelico system receives natural gas from our Minden and Ada gathering systems and processing plants as well as from interconnects with other intrastate pipelines that deliver gas from other producing areas in eastern Texas and northern Louisiana, and from other wellhead receipt points directly connected to the system.

For natural gas that is gathered and then processed at our Minden or Ada processing plants, we receive the wellhead natural gas from the producers primarily under percentage-of-proceeds arrangements or fee-based arrangements. Our gross margin generated from percentage-of-proceeds gathering and processing contracts is directly correlated to the price of natural gas, NGLs and condensate. To minimize this potential future volatility we have entered into a series of derivative financial instrument agreements to hedge our natural gas, NGLs and condensate. As a result of these transactions, we have hedged a significant portion of our share of anticipated natural gas, NGLs and condensate attributable to these contracts through 2010. We have also hedged a significant portion of our condensate commodity price risk through 2011.

We gather and transport natural gas on the Pelico system under a combination of fee-based transportation agreements and merchant arrangements. We have also entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that requires DCP Midstream, LLC to supply Pelico s system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index-based price less a contractually agreed to marketing fee. In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index. We account for such a physical fixed price transaction and the related financial derivative as a fair value hedge. We occasionally will enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting.

Competition

The North Louisiana system experiences competition in all of its local markets. The North Louisiana system s principal areas of competition include obtaining natural gas supplies for the Minden processing plant and Ada processing plant and natural gas transportation customers for the Pelico system. The North Louisiana system s competitors include major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport and/or market natural gas. The Pelico system competes with interstate and intrastate pipelines. These include pipelines owned by Regency Intrastate Gas, LLC, Gulf South Pipeline Company and Tennessee Natural Gas Company. The Minden and Ada processing plants compete with other natural gas gathering and processing systems owned by XTO Energy Inc., Regency Intrastate Gas, LLC and Gulf South Pipeline Company, as well as producer-owned systems.

Wholesale Propane Logistics Segment

General

We operate a wholesale propane logistics business in the Midwest and northeastern United States. We own assets and do business in the states of New York, Pennsylvania, Ohio, Massachusetts, Vermont, New Hampshire, Rhode Island, Connecticut and Maine. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Midwest and the northeastern areas of the United States. We sell propane on a wholesale basis to retail propane distributors who in turn resell propane to their retail customers.

Due to our multiple propane supply sources, long-term propane supply purchase arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our retail propane distribution customers with reliable deliveries of propane during periods of tight supply such as the winter months when their retail customers consume the most propane for home heating. In particular, we generally offer our customers the ability to obtain propane supply volumes from us in the winter months that are significantly greater than the volume of propane purchased from us in the summer. We believe these factors generally allow us to maintain favorable relationships with our customers.

We manage our wholesale propane margins by selling propane to retail propane distributors under annual sales agreements negotiated each spring that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year, and we manage this commodity price risk by entering into either offsetting physical purchase agreements or financial derivative instruments, with either DCP Midstream, LLC or third parties, that generally match the quantities of propane subject to these fixed price sales agreements. The financial derivatives are accounted for using mark-to-market accounting. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. In addition, we may, on occasion, use financial derivatives to manage the value of our propane inventories.

Pipeline deliveries to the northeast market, which consists of New York, Pennsylvania, Ohio, Massachusetts, Vermont, New Hampshire, Rhode Island, Connecticut and Maine, in the winter season are generally at capacity and competing pipeline dependent terminals can have supply constraints or outages during peak market conditions. Our system of terminals has substantial excess capacity, which provides us with opportunities to increase our volumes with minimal additional cost. Additionally, we are constructing a propane pipeline terminal located in Midland, Pennsylvania that is expected to be operational in the second quarter of 2007, and we are

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actively seeking new rail terminals in the northeastern market through acquisition or construction to expand our distribution capabilities.

Our Terminals

Our operations include six propane rail terminals with aggregate storage capacity of 25 MBbls, one propane marine terminal with storage capacity of 450 MBbls, one propane pipeline terminal under construction and access to several open access pipeline terminals. A map representing the location of our propane rail terminals, our leased propane marine terminal and the open access pipeline terminals that we utilize is set forth below:

We own our rail terminals and lease the land on which the terminals are situated under long-term leases. Our marine terminal is leased from TEPPCO Partners, LP under a 10-year lease expiring in 2014. Each of our rail terminals consist of two to four propane tanks with capacity of between 30,000 and 90,000 gallons for storage, and two high volume loading racks for loading propane into trucks. Our aggregate truck-loading capacity is approximately 400 trucks per day. We could expand each of our terminals loading capacity by adding a third loading rack to handle future growth. High volume submersible pumps are utilized to enable trucks to fully load within 15 minutes. Each facility also has the ability to unload multiple railcars simultaneously. We have numerous railcar leases that allow us to increase our storage and throughput capacity as propane demand increases. Each terminal relies on leased rail trackage for the storage of the majority of its propane inventory in these leased railcars. These railcars mitigate the need for larger numbers of fixed storage tanks and reduce initial capital needs when constructing a terminal. Each railcar holds approximately 30,000 gallons of propane.

The number and geographic locations of our terminals, as well as our access to propane supply from multiple supply sources, allows us:

- to provide our customers with reliable deliveries during periods of tight supply and, as a result, we are often able to offer our customers a favorable winter/summer volume ratio; and the flexibility to manage physical inventories during periods of lower propane prices such as those typically experienced in the summer months.

These factors have allowed us to remain a supplier to many of the large retail distributors in the northeastern United States. As a result, we serve as the baseload provider of propane supply to many of our retail propane distribution customers.

We are also actively seeking to expand our wholesale propane distribution business into the upper Midwest and Mid-Atlantic states. In this regard, we currently have a propane pipeline terminal under construction in western Pennsylvania that was originally expected to be operational during the fourth quarter of 2006. This propane pipeline terminal is now expected to be operational in the second quarter of 2007. This terminal, which will have storage capacity of 56 MBbls, is expected to position us favorably in establishing a presence in this region.

Propane Supply

Our wholesale propane business has a strategic network of supply arrangements under multi-year agreements providing approximately 7,760 MBbls per year of supply under index-based pricing. The remaining supply is purchased on annual or month-to-month terms to match our anticipated sale requirements. Generally, these agreements cover a specific volume per month and pricing is based on index prices.

For our rail terminals, we contract for propane at various major supply points in the United States and Canada, and transport the product to our terminals under long-term rail commitments, which provide fixed transportation costs that are subject to prevailing fuel surcharges. These long-term rail commitments have terms expiring in 2007 through 2010. We also purchase propane supply from natural gas fractionation plants and crude oil refineries located in the Texas and Louisiana Gulf Coast areas and transport this supply of propane on TEPPCO Partners, LP s pipeline from the Mont Belvieu market hub in east Texas under published tariff rates to open access terminals located in the Midwest and northeastern United States. Through this process, we take custody of the propane and either sell it in the wholesale market or store it at our facilities. For our marine terminal, we contract under annual agreements for delivered shipments of propane. Under these agreements, we are not required to pay for the propane until delivery of the propane to our customers at the rack delivery point, based upon an agreed-to schedule, which minimizes the amount of inventory we carry. The port where our marine terminal facility is located has recently been expanded, and we can now receive propane supply from the largest propane tankers currently in service.

During 2006, our primary suppliers of propane were Aux Sable Liquid Products LP and Shell International Trading and Shipping Company, which collectively accounted for approximately 22% of our consolidated purchases of natural gas, propane and NGLs in 2006. We had no supplier who accounted for more than 10% of our consolidated purchases of natural gas, propane and NGLs in 2005 or 2004.

Markets and Customers

We typically sell propane to retail propane distributors under annual sales agreements negotiated each spring that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year. We manage this commodity price risk by entering into either offsetting physical purchase agreements or financial derivative instruments, with either DCP Midstream, LLC or third parties, that generally match the quantities of propane subject to these fixed price sales agreements. Our ability to help our clients manage their commodity price exposure by offering propane at a fixed price may lead to a larger customer base. Historically, approximately 75% of the gross margin generated by our wholesale propane business is earned in the heating season months of October through April, which corresponds to the general market demand for propane. No individual customer in our Wholesale Propane Logistics segment accounted for more than 10% of our total operating revenues for the years ended December 31, 2006, 2005 and 2004.

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Competition

The wholesale propane business is highly competitive in the northeastern region of the United States. Our wholesale propane business competitors include major integrated oil and gas and energy companies, and interstate and intrastate pipelines. These competitors include BP PLC, Trammo Gas, SemStream LP and Enterprise Products Partners.

NGL Logistics Segment

General

Our NGL transportation assets consist of our wholly-owned approximately 68-mile Seabreeze intrastate NGL pipeline and our wholly-owned approximately 39-mile Wilbreeze intrastate NGL pipeline, both of which are located in Texas, and a 45% interest in the approximately 317-mile Black Lake interstate NGL pipeline located in Louisiana and Texas. These NGL pipelines transport mixed NGLs from natural gas processing plants to fractionation facilities, a petrochemical plant and an underground NGL storage facility. In aggregate, our NGL transportation business has 73 MBbls/d of capacity and in 2006 average throughput was approximately 25 MBbls/d.

In the markets we serve, our pipelines are the sole pipeline facility transporting NGLs from the supply source. Our pipelines provide transportation services to customers on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the mixed NGLs from the natural gas. As a result, we have experienced periods in the past, and will likely experience periods in the future, when higher natural gas prices reduce the volume of NGLs produced at plants connected to our NGL pipelines.

NGL Pipelines

Seabreeze and Wilbreeze Pipelines. Our Seabreeze pipeline is an approximately 68-mile private NGL pipeline with current capacity configured at 33 MBbls/d. It is located along the Gulf Coast area of southeastern Texas. For 2006, average throughput on the pipeline was approximately 20 MBbls/d. The Seabreeze pipeline was put into service in 2002 to deliver an NGL mix to the Formosa Point Comfort Chemical Complex from Williams Markham Gas Plant, a large processing plant with processing capacity of approximately 340 MMcf/d located in Matagorda County, Texas; Enterprise Products Matagorda Plant, a large processing plant with capacity of approximately 250 MMcf/d located in Matagorda County, Texas; and TEPPCO Partners, L.P. s South Dean NGL pipeline. The Seabreeze pipeline is the sole NGL pipeline for the two processing plants and is the only delivery point for the South Dean NGL pipeline. This third party NGL pipeline transports NGLs from five natural gas processing plants located in southeastern Texas that have aggregate processing capacity of approximately 1.6 Bcf/d. Three of these processing plants are owned by DCP Midstream, LLC. The seven processing plants that produce NGLs that flow into the Seabreeze pipeline process natural gas produced in southern Texas and offshore in the Gulf of Mexico (Boomvang and Nansen offshore production platforms and the Matagorda Island Production Facility). The Seabreeze pipeline delivers the NGLs it receives from these sources to a fractionator at the Formosa Point Comfort Chemical Complex and the Texas Brine Salt Dome storage facility.

In December 2006, we completed construction of our Wilbreeze pipeline, an approximately 39-mile NGL pipeline to connect a DCP Midstream, LLC gas processing plant to our Seabreeze pipeline. The project is supported by a 10-year NGL product dedication agreement with DCP Midstream, LLC. Current capacity of the Wilbreeze pipeline is configured at 11 MBbls/d. Volumes from DCP Midstream, LLC are expected to be approximately 5 MBbls/d.

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A map illustrating the location of the Seabreeze and Wilbreeze pipelines is set forth below:

Effective December 1, 2005, we entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will purchase the NGLs that were historically purchased by us, and DCP Midstream, LLC will pay us to transport the NGLs pursuant to a fee-based rate that will be applied to the volumes transported. We have entered into this fee-based contractual arrangement with the objective of generating approximately the same operating income per barrel transported that we realized when we were the purchaser and seller of NGLs. We do not take title to the products transported on the NGL pipelines; rather, the shipper retains title and the associated commodity price risk. DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a 17-year transportation agreement expiring in 2022. The Seabreeze pipeline only collects fee-based transportation revenue under this agreement. DCP Midstream, LLC receives its supply of NGLs that it then transports on the Seabreeze pipeline under a 20-year NGL purchase agreement with Williams expiring in 2022 and a 5-year NGL purchase agreement with Enterprise Products Partners expiring in 2007. Under these agreements, Williams and Enterprise Products Partners have each dedicated all of their respective NGL production from these processing plants to DCP Midstream, LLC. The Seabreeze pipeline delivers all of DCP Midstream, LLC s volumes to a fractionator at the Formosa Point Comfort Chemical Complex and the Texas Brine Salt Dome storage facility operated by Underground Services Markam. DCP Midstream, LLC has a 20-year long-term sales agreement with Formosa expiring in 2022. Additionally, DCP Midstream, LLC has a 10-year transportation agreement with TEPPCO Partners, L.P. expiring in 2012 that covers all of the NGL volumes transported on TEPPCO Partners, L.P. s South Dean NGL pipeline for delivery to the Seabreeze pipeline.

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Black Lake Pipeline. We own a 45% interest in Black Lake, which owns an approximately 317-mile Federal Energy Regulatory Commission, or FERC, regulated interstate NGL pipeline with 40 MBbls/d of capacity. For 2006, average throughput on the pipeline at our 45% interest was approximately 5 MBbls/d. A map representing the location of the Black Lake pipeline is set forth below:

The Black Lake pipeline was constructed in 1967 and delivers NGLs from processing plants in northern Louisiana and southeastern Texas to fractionation plants at Mont Belvieu on the Texas Gulf Coast. The Black Lake pipeline receives NGL mix from three natural gas processing plants in northern Louisiana, including our Minden plant, Regency Intrastate Gas, LLC s Dubach processing plant and Chesapeake Energy Corporation s Black Lake processing plant. The Black Lake pipeline is the sole NGL pipeline for all of these natural gas processing plants in northern Louisiana, as well as the Ceritas South Raywood processing plant located in southeastern Texas. The Black Lake pipeline also receives NGL mix from XTO Energy Inc. s Cotton Valley processing plant. In addition, the Black Lake pipeline receives NGL mix from Eagle Rock Energy Partners, LP s Brookeland natural gas processing plant located in southeastern Texas under a five-year dedication agreement, which expires in 2011.

There are currently five significant active shippers on the pipeline, with DCP Midstream, LLC historically being the largest, representing approximately 54% of total throughput in 2006. The Black Lake pipeline generates revenues through a FERC-regulated tariff. The average rate per barrel was $0.94 in 2006.

Black Lake is a partnership that is owned 45% by us, 5% by an affiliate of DCP Midstream, LLC and 50% by BP PLC. BP PLC is the operator of the pipeline. Black Lake is required by its partnership agreement to make monthly cash distributions equal to 100% of its available cash for each month, which is defined generally as receipts plus reductions in cash reserves less disbursements and increases in cash reserves. In anticipation of a pipeline integrity project, Black Lake suspended making monthly cash distributions in December 2004 in order to reserve cash to pay the expenses of this project. We expect that this project will be completed by the end of 2007; however, we anticipate cash distributions will resume prior to the completion of this project.

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Customers

We had no customers that accounted for more than 10% of our total operating revenues for the year ended December 31, 2006. We had one NGL customer, Formosa Hydrocarbons Company, Inc., that accounted for 17% and 18% of our total operating revenues for the years ended December 31, 2005 and 2004, respectively.

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, or DOT, under the Accountable Pipeline and Safety Partnership Act of 1996, referred to as the Hazardous Liquid Pipeline Safety Act, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. The Hazardous Liquid Pipeline Safety Act covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in material compliance with these Hazardous Liquid Pipeline Safety Act regulations.

We are also subject to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines and some gathering lines in high-consequence areas within 10 years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that will require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. We currently estimate we will incur costs of approximately $4.1 million between 2007 and 2011 to implement integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program. DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from 2005 through 2007 and up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of pipeline integrity testing that occurred during 2006. Reimbursements related to the Seabreeze pipeline integrity repairs in 2006 were not significant.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we or the entities in which we own an interest operate. Our natural gas pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or 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 Environmental Protection Agency, or 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

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above the specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety.

Regulation of Operations

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

Intrastate Natural Gas Pipeline Regulation

Intrastate natural gas pipeline operations are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. However, to the extent that an intrastate pipeline system transports natural gas in interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. Under Section 311, intrastate pipelines providing interstate service may avoid jurisdiction that would otherwise apply under the Natural Gas Act of 1938, or NGA. Section 311 regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. Additionally, the terms and conditions of service set forth in the intrastate pipeline s Statement of Operating Conditions are subject to FERC approval. Failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline s FERC-approved Statement of Operating Conditions could result in the assertion of federal NGA jurisdiction by FERC and/or the imposition of administrative, civil and criminal penalties. The Pelico system is subject to FERC jurisdiction under Section 311 of the NGPA. The maximum rate that the Pelico system may currently charge is $0.1965 per MMBtu. The Pelico system filed a new Section 311 rate case with FERC on December 1, 2006, pursuant to a FERC order. The rate case included a transportation rate of $0.2617 per MMBtu and no other changes to the Pelico system s terms and conditions of service. The rate case is pending, but we do not expect the outcome to have a material adverse effect on our business.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We believe that the natural gas pipelines in our North Louisiana system meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going legislation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

Louisiana s Pipeline Operations Section of the Department of Natural Resources Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana, and has authority to review and authorize natural gas transportation transactions, and the construction, acquisition, abandonment and interconnection of physical facilities. Historically, apart from pipeline safety, it has not acted to exercise this jurisdiction respecting gathering facilities.

Our purchasing, gathering and intrastate transportation operations are subject to Louisiana and Arkansas ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling.

Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of the FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

Propane Regulation

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies, and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate our facilities, some of which may be material to our propane operations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in compliance in all material respects with applicable laws and regulations.

Interstate NGL Pipeline Regulation

The Black Lake pipeline is an interstate NGL pipeline subject to FERC regulation. The FERC regulates interstate NGL pipelines under its Oil Pipeline Regulations, the Interstate Commerce Act, or ICA, and the Elkins Act. FERC requires that interstate NGL pipelines file tariffs containing all the rates, charges and other terms for services performed. The ICA requires that tariffs apply to the interstate movement of NGLs, usually meaning that the origin point and destination point are in different states, as is the case with the Black Lake pipeline. Pursuant to the ICA, rates can be challenged at FERC either by protest when they are initially filed or increased, or by complaint at any time they remain on file with FERC.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, transporting, processing or storing natural gas, propane, NGLs and other products is subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment.

As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat, fractionate and process natural gas. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

We or the entities in which we own an interest inspect the pipelines regularly using equipment rented from third party suppliers. Third parties also assist us in interpreting the results of the inspections.

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DCP Midstream, LLC has agreed to indemnify us in an aggregate amount not to exceed $15.0 million for three years from the closing of our initial public offering for environmental noncompliance and remediation liabilities associated with the assets transferred to us and occurring or existing before the closing date of December 7, 2005.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We believe that we are in substantial compliance with these requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances or solid wastes (including petroleum hydrocarbons). These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste, and may impose strict, joint and several liability for the investigation and remediation of areas, at a facility where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the petroleum exclusion of CERCLA Section 101(14) that currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate solid wastes, including hazardous wastes, that are subject to the requirements of the Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA s hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

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

Water

The Federal Water Pollution Control Act of 1972, also referred to as the Clean Water Act, or CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The EPA has promulgated regulations that require us to have permits in order to discharge certain storm water run-off. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water run-off. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

Title to Properties and Rights-of-Way

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

Employees

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, or the General Partner, which is wholly-owned by DCP Midstream, LLC. As of December 31, 2006, the General Partner or its affiliates employed nine people directly and approximately 109 people who provided direct support for our operations through DCP Midstream, LLC. None of these employees are covered by collective bargaining agreements. Our General Partner considers its employee relations to be good.

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General

We make certain filings with the Securities and Exchange Commission, or 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, available free of charge through our website, *www.dcppartners.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 *www.sec.gov.* Our annual reports to unitholders, 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. You should consider carefully the following risk factors together with all of the other information included in this annual report in evaluating an investment in our common units.

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

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to make cash distributions to holders of our common units and subordinated units at the initial distribution rate under our cash distribution policy.

In order to make our cash distributions at our minimum distribution rate of $0.35 per common unit per quarter, or $1.40 per unit per year, we require available cash of approximately $6.3 million per quarter, or $25.3 million per year, based on the common units, Class C units and subordinated units currently outstanding. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at the minimum 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, level of production of, and demand for, natural gas, propane, condensate and NGLs;
- the volume of natural gas we gather, treat, compress, process, transport and sell, the volume of propane and NGLs we transport and sell, and the volumes of propane we store;
- the relationship between natural gas and NGL prices;
- the level of competition from other midstream energy companies;

- the impact of weather conditions on the demand for natural gas and propane;
- 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;
- the cost and form of payment of acquisitions;

our debt service requirements and other liabilities;

fluctuations in our working capital needs;

our ability to borrow funds and access capital markets;

restrictions contained in our debt agreements; and

the amount of cash reserves established by our general partner.

The amount of cash we have available for distribution to holders of our common units and subordinated units depends primarily on our cash flow and not solely on profitability.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of supplies of natural gas and NGLs, which are dependent on certain factors beyond our control. Any decrease in supplies of natural gas or NGLs could adversely affect our business, operating results and our ability to make cash distributions.

Our gathering and transportation pipeline systems are connected to or dependent on the level of production from natural gas wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and NGL pipelines and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and NGLs, and to attract new customers to our assets include the level of successful drilling activity near these systems, and our ability to compete for volumes from successful new wells.

The level of drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is natural gas prices. Currently, natural gas prices are high in relation to historical prices. For example, the rolling twelve-month average NYMEX daily settlement price of natural gas futures contracts has increased from $3.22 per MMBtu as of December 31, 2002 to $7.23 per MMBtu as of December 31, 2006. If the high price for natural gas were to decline, the level of drilling activity could decrease. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering and pipeline transportation systems and our natural gas treating and processing plants, which would lead to reduced utilization of these assets. Other factors that impact production decisions include producers capital budgets, the ability of producers to obtain necessary drilling and other governmental permits, access to drilling rigs and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to you.

The cash flow from our Natural Gas Services segment is affected by natural gas, NGL and condensate prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units.

Our Natural Gas Services segment is affected by the level of natural gas, NGL and condensate prices. NGL and condensate prices generally fluctuate on a basis that correlates to fluctuations in crude oil prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. The markets and prices for natural gas, NGLs, condensate and crude oil depend upon factors beyond our control. These factors include supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather;
- the level of domestic and offshore production;
- the availability of imported natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percentage-of-proceeds arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers for an agreed percentage of the proceeds from the sale of residue gas and NGLs resulting from our processing activities, and then sell the resulting residue gas and NGLs at market prices. Under these types of arrangements, our revenues and our cash flows increase or decrease, whichever is applicable, as the price of natural gas and NGLs fluctuate. We have hedged a significant portion of our share of anticipated natural gas and NGL commodity price risk associated with these arrangements through 2010. Additionally, as part of our gathering operations, we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices. We have hedged a significant portion of our share of anticipated condensate commodity price risk through 2011. For additional information regarding our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

Our hedging activities may have a material adverse effect on our earnings, profitability, cash flows and financial condition.

We have hedged a significant portion of our expected natural gas and NGL commodity price risk relating to our percentage-of-proceeds gathering and processing contracts through 2010 by entering into derivative financial instruments relating to the future price of natural gas and crude oil. In addition, we have hedged a significant portion of our expected condensate commodity price risk relating to condensate recovered from our gathering operations through 2011, respectively, by entering into derivative financial instruments relating to the future price of crude oil. Additionally, we have entered into interest rate swap agreements to hedge a portion of the variable rate revolving debt under our Credit Agreement to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. The intent of these arrangements is to reduce the volatility in our cash flows resulting from fluctuations in commodity prices and interest rates.

We will continue to evaluate whether to enter into any new hedging arrangements, but there can be no assurance that we will enter into any new hedging arrangement or that our future hedging arrangements will be on terms similar to our existing hedging arrangements. Also, we may seek in the future to further limit our exposure to changes in natural gas, NGL and condensate commodity prices, and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent we hedge our commodity price and interest rate risk, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

Despite our hedging program, we remain exposed to risks associated with fluctuations in commodity prices. The extent of our commodity price risk is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. Furthermore, we have entered into derivative transactions related to only a portion of the volume of our expected natural gas supply and production of NGLs and condensate from our processing plants; as a result, we will continue to have direct commodity price risk to the unhedged portion. Our actual future production may be significantly higher or lower than we estimate at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimate, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our liquidity.

As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our earnings and cash flows. In addition, even though our management monitors our hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, or our hedging policies and procedures are not properly followed or do not work as planned. Our earnings and cash flows could also be subject to increased volatility in the event our derivatives do not continue to qualify for hedge accounting. Also, to the extent we are unable to obtain, or choose not to seek hedge accounting in conjunction with any future acquisitions as a result of the type of commodity risk assumed, or structure of such acquisition, our earnings and cash flows could be subject to increased volatility. We cannot assure you that the steps we take to monitor our hedging activities will detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. For additional information regarding our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk.

We typically do not obtain independent evaluations of natural gas reserves dedicated to our gathering and 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 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 systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems is less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas on our systems in the future could be less than we anticipate. A decline in the volumes of natural gas on our systems could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to you.

We depend on certain natural gas producer customers for a significant portion of our supply of natural gas and NGLs. The loss of any of these customers could result in a decline in our volumes, revenues and cash available for distribution.

We rely on certain natural gas producer customers for a significant portion of our natural gas and NGL supply. Our two largest suppliers for the year ended December 31, 2006, Anadarko Petroleum Corporation and ConocoPhillips, accounted for approximately 31% and 29%, respectively, of our 2006 natural gas supply in our Natural Gas Services segment. In our NGL Logistics segment, our largest NGL supplier is DCP Midstream, LLC, who obtains NGLs from various third party producer customers. While some of these customers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts, on favorable terms, if at all. The loss of all or even a portion of the natural gas and NGL volumes supplied by these customers, as a result of competition or otherwise, could have a material adverse effect on our business, results of operations and financial condition, unless we were able to acquire comparable volumes from other sources.

If we are not able to purchase propane from our principal suppliers, our results of operations in our wholesale propane logistics business would be adversely affected.

Most of our propane purchases are made under supply contracts that have a term of between one to five years and provide various pricing formulas. Our primary suppliers of propane collectively accounted for approximately 48% of the propane volumes we purchased in 2006. In the event that we are unable to purchase propane from our significant suppliers, our failure to obtain alternate sources of supply at competitive prices and on a timely basis would hurt our ability to satisfy customer demand, reduce our revenues and adversely affect our results of operations.

We may not be able to grow or effectively manage our growth.

A principal focus of our strategy is to continue to grow the per unit distribution on our units by expanding our business. Our future growth will depend upon a number of factors, some of which we can control and some of which we cannot. These factors include our ability to:

- identify businesses engaged in managing, operating or owning pipelines, processing and storage assets or other midstream assets for acquisitions, joint ventures and construction projects;
- consummate accretive acquisitions or joint ventures and complete construction projects;
- appropriately identify any liabilities associated with any acquired businesses or assets;
- integrate any acquired or constructed businesses or assets successfully with our existing operations and into our operating and financial systems and controls;
- hire, train and retain qualified personnel to manage and operate our growing business; and
- obtain required financing for our existing and new operations.

A deficiency in any of these factors could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from acquisitions, joint ventures or construction projects. In addition, competition from other buyers could reduce our acquisition opportunities or cause us to pay a higher price than we might otherwise pay. In addition, DCP Midstream, LLC and its affiliates are not restricted from competing with us. DCP Midstream, LLC and its affiliates may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

We may not successfully balance our purchases and sales of natural gas and propane, which would increase our exposure to commodity price risks.

We purchase from producers and other customers a substantial amount of the natural gas that flows through our natural gas gathering, processing and transportation systems for resale to third parties, including natural gas marketers and end-users. In addition, in our wholesale propane logistics business, we purchase propane from a variety of sources and resell the propane to retail distributors. We may not be successful in balancing our purchases and sales. A producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to be unbalanced. While we attempt to balance our purchases and sales, if our purchases and sales are unbalanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income and cash flows.

Our NGL pipelines could be adversely affected by any decrease in NGL prices relative to the price of natural gas.

The profitability of our NGL pipelines is dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost (principally that of natural gas as a feedstock and fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices reduce the volume of natural gas processed at plants connected to our NGL pipelines, which would reduce the volumes and gross margins attributable to our NGL pipelines.

If third party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities become unavailable to transport or produce natural gas and NGLs, our revenues and cash available for distribution could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. For example, the volumes of NGLs that are transported on our Seabreeze pipeline and the Black Lake pipeline are dependent upon a number of processing plants and NGL pipelines owned and operated by DCP Midstream, LLC and other third parties, including Williams Markham Gas Plant, Enterprise Products Matagorda Plant, TEPPCO Partners, L.P. s South Dean NGL pipeline, Regency Intrastate Gas, LLC s Dubach processing plant and Chesapeake Energy Corporation s Black Lake processing plant. In addition, our Pelico pipeline system is interconnected to several third party intrastate and interstate pipelines, including pipelines owned by Southern Natural Gas Company, Texas Gas Transmission, LLC, CenterPoint Energy Mississippi River Transmission Corporation, Texas Eastern Transmission LP, CenterPoint Energy Gas Transmission Company, Crosstex LIG, LLC, Gulf South Pipeline Company, Tennessee Natural Gas Company and Regency Intrastate Gas, LLC. Since we do not own or operate any of these pipelines or other facilities, their continuing operation is not within our control. If any of these third party pipelines and other facilities become unavailable to transport or produce natural gas and NGLs, our revenues and cash available for distribution could be adversely affected.

Our wholesale propane logistics business would be adversely affected if service at our terminals were interrupted.

Historically, a substantial portion of the propane we purchase to support our wholesale propane logistics business is delivered to us at our rail terminals or is delivered by ship to us at our leased marine terminal in Providence, Rhode Island. We also rely on shipments of propane via TEPPCO Partners, LP s pipeline to open access terminals. Any significant interruption in the service at these terminals would adversely affect our ability to obtain propane, which could reduce the amount of propane that we distribute, our revenues, or cash available for distribution.

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

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

Since weather conditions may adversely affect the overall demand for propane, our wholesale propane business is vulnerable to, and could be adversely affected by, warm winters.

Weather conditions could have an impact on the demand for wholesale propane because the end-users of propane depend on propane principally for heating purposes. As a result, warm weather conditions could adversely impact the demand for and prices of propane. Actual weather conditions can substantially change

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from one year to the next. Furthermore, since our wholesale propane logistics business is located almost solely in the northeast, warmer than normal temperatures in the northeast can decrease the total volume of propane we sell. Such conditions may also cause downward pressure on the price of propane, which could result in a lower of cost or market adjustment to the value of our inventory. Consequently, our operating results may vary due to actual changes in temperature.

Competition from alternative energy sources and energy efficiency and technological advances may reduce the demand for propane, which could reduce the volumes of propane that we distribute.

Competition from alternative energy sources, including natural gas and electricity, has been increasing as a result of reduced regulation of many utilities, including natural gas and electricity. In addition, propane competes with heating oil primarily in residential applications. Propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a less expensive source of energy than propane. The gradual expansion of natural gas distribution systems and availability of natural gas in the northeast, which has historically depended upon propane, could reduce the demand for propane, which could adversely affect the volumes of propane that we distribute. In addition, stricter conservation measures in the future or technological advances in heating, conservation, energy generation or other devices could reduce the demand for propane in the future, which could adversely affect the volumes of propane that we distribute.

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

Our natural gas gathering and intrastate transportation operations are generally exempt from FERC regulation under the NGA, except for Section 311 as discussed below, but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC s policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and 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 oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on future determinations by FERC and the courts.

In addition, the rates, terms and conditions of some of the transportation services we provide on our Pelico pipeline system is subject to FERC regulation under Section 311 of the NGPA. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The Pelico system is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under a rate settlement with FERC. The Pelico system made a new rate filing on December 1, 2006, that proposed a transportation rate of $0.2617 per MMBtu, and no changes to the terms and conditions of the Pelico system s Section 311 transportation services. The Black Lake pipeline system is an interstate transporter of NGLs and is subject to FERC jurisdiction under the Interstate Commerce Act and the Elkins Act. For more information regarding regulation of our operations, please read Business Regulation of Operations.

Other state and local regulations also affect our business. Our non-proprietary gathering lines are subject to ratable take and common purchaser statutes in Louisiana. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas

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producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination. Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our proprietary gathering lines currently are subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge proprietary status of a line, or the rates, terms and conditions of a gathering line providing transportation service. Please read Business Regulation of Operations.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances or hydrocarbons into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example, (1) the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions; (2) the federal Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the discharge of waste from our facilities; and (3) the Comprehensive Environmental Response Compensation and Liability Act of 1980, or CERCLA, also known as Superfund, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental regulations, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance or from indemnification from DCP Midstream, LLC. Please read Business Environmental Matters.

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

Pursuant to the Pipeline Safety Improvement Act of 2002, the United States Department of Transportation, or DOT, has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in high consequence areas. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;

repair and remediate the pipeline as necessary; and

implement preventive and mitigating actions.

We currently estimate that we will incur costs of approximately $4.1 million between 2007 and 2011 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. While DCP Midstream, LLC has agreed to indemnify us for our pro rata share of any capital contributions associated with certain repair costs relating to the Black Lake pipeline resulting from such testing program, the actual costs of making such repairs, including any lost cash flows resulting from shutting down our pipelines during the pendency of such repairs, could substantially exceed the amount of such indemnity.

We currently transport all of the NGLs produced at our Minden plant on the Black Lake pipeline. According, in the event that the Black Lake pipeline becomes inoperable due to any necessary repairs resulting from our integrity testing program or for any other reason for any significant period of time, we would need to transport NGLs by other means. The Minden plant has an existing alternate pipeline connection that would permit the transportation of NGLs to a local fractionator for processing and distribution with sufficient pipeline takeaway and fractionation capacity to handle all of the Minden plant s NGL production. We do not, however, currently have commercial arrangements in place with the alternative pipeline. While we believe we could establish alternate transportation arrangements, there can be no assurance that we will in fact be able to enter into such arrangements.

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

One of the ways we intend to grow our business is through the construction of new midstream assets. The construction of additions or modifications to our existing systems or propane terminals, and the construction of new midstream assets involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule or at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we construct a new pipeline or terminal, the construction may occur over an extended period of time, and we will not receive any material increases in revenues until the project is completed. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we 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, transportation and propane terminal assets may require us to obtain new rights-of-way prior to constructing new facilities. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines, expand our network of propane terminals, 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. In addition, the construction of additional propane terminals may require greater capital investment if the commodity prices of certain supplies such as steel increase. If the cost of renewing or obtaining new rights-of-way increases, or the cost of constructing new facilities is impacted by certain commodity prices, our cash flows could be adversely affected.

If we do not make acquisitions on economically acceptable terms, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are: (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them; (2) unable to obtain financing for these acquisitions on economically acceptable terms; or (3) outbid by competitors, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations per unit. Additionally, net assets contributed by DCP Midstream, LLC represent a transfer of net assets between entities under common control, and are recognized at DCP Midstream, LLC s basis in the net assets transferred. The amount of the purchase price in excess of DCP Midstream, LLC s basis in the net assets, if any, is recognized as a reduction to partners equity. Contributions from DCP Midstream, LLC may significantly increase our debt to capitalization ratios.

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

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management s and employees attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

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

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

We do not own all of the land on which our pipelines, facilities and rail terminals have been constructed, 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 if such rights of way lapse or terminate. We obtain the rights to construct and operate our pipelines, surface sites and rail terminals on 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 or otherwise, could have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions to you.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

Our operations are subject to many hazards inherent in the gathering, compressing, treating, processing and transporting of natural gas, propane and NGLs, and the storage of propane, including:

- damage to pipelines, plants and terminals, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;

- inadvertent damage from construction, farm and utility equipment;

- leaks of natural gas, propane, NGLs and other hydrocarbons or losses of natural gas, propane or NGLs as a result of the malfunction of equipment or facilities;

contaminants in the pipeline system;

fires and explosions; and

other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent to our business. In accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, which may include toxic tort claims, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition. In addition, 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. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 7, 2005, we entered into a credit facility, consisting of a $100.1 million collateralized term loan facility and a $250.0 million revolving credit facility for working capital and other general partnership purposes. We had outstanding balances of $100.0 million under the term loan facility and $168.0 million under the revolving credit facility as of December 31, 2006. The term loan facility maximum borrowing is $100.1 million, and once repaid such amount may not be reborrowed. However, once a portion of the term loan is repaid, the revolving credit facility will increase ratably. We continue to have the ability to incur additional debt, subject to limitations in our credit facility. Our level of debt could have 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;

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

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

our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to obtain new debt funding or service our existing 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. In addition, our ability to service debt under our revolving credit facility will depend on market interest rates, since we anticipate that the interest rates applicable to our borrowings will fluctuate with movements in interest rate markets. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all. During 2006 we entered into interest rate swap agreements to hedge the variable interest rate on $125.0 million of the balance outstanding under our credit agreement. For additional information regarding our hedging activities, please read

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Management s Discussion and Analysis of financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk Interest Rate Risk.

Restrictions in our credit facility will limit our ability to make distributions to you and may limit our ability to capitalize on acquisitions and other business opportunities.

Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our credit facility contains covenants requiring us to maintain certain financial ratios and tests. Any subsequent replacement of our credit facility or any new indebtedness could have similar or greater restrictions. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Requirements.

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

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. 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, incur debt or for other purposes.

Due to our lack of industry and geographic diversification, adverse developments in our midstream operations or operating areas would reduce our ability to make distributions to our unitholders.

We rely on the revenues generated from our midstream energy businesses, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas, propane, condensate and NGLs. Due to our lack of diversification in industry type and location, an adverse development in one of these businesses or operating areas would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

We are exposed to the credit risks of our key producer customers and propane purchasers, and any material nonpayment or nonperformance by our key producer customers or our propane purchasers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our producer customers and propane purchasers. Any material nonpayment or nonperformance by our key producer customers or our propane purchasers could reduce our ability to make distributions to our unitholders. Furthermore, some of our producer customers or our propane purchasers may be highly leveraged and subject to their own operating and regulatory risks, which could increase the risk that they may default on their obligations to us.

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 or the attacks in London, and the threat of future terrorist attacks on our industry in general, and on us in particular, is not known at this time. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil supplies, propane shipments or storage facilities, and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

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

Risks Inherent in an Investment in Us

DCP Midstream, LLC controls our general partner, which has sole responsibility for conducting our business and managing our operations. DCP Midstream, LLC has conflicts of interest, which may permit it to favor its own interests to your detriment.

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

- neither our partnership agreement nor any other agreement requires DCP Midstream, LLC to pursue a business strategy that favors us. DCP Midstream, LLC s directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of DCP Midstream, LLC, which may be contrary to our interests;

- our general partner is allowed to take into account the interests of parties other than us, such as DCP Midstream, LLC and its affiliates, in resolving conflicts of interest;

- DCP Midstream, LLC and its affiliates, including Spectra Energy and ConocoPhillips, are not limited in their ability to compete with us. Please read DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us below;

- our general partner may make a determination to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights without the approval of the special committee of our general partner or our unitholders;

- some officers of DCP Midstream, LLC who provide services to us also will devote significant time to the business of DCP Midstream, LLC, and will be compensated by DCP Midstream, LLC for the services rendered to it;

- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;

- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units;

our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

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

our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;

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

our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

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

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

Neither our partnership agreement nor the Omnibus Agreement between us, DCP Midstream, LLC and others will prohibit DCP Midstream, LLC and its affiliates, including Spectra Energy and ConocoPhillips, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, DCP Midstream, LLC and its affiliates, including Spectra Energy and ConocoPhillips, 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. Each of these entities is a large, established participant in the midstream energy business, and each has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and cash available for distribution.

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

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

Our partnership agreement limits our general partner s fiduciary duties to holders of our common units and subordinated units.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, DCP Midstream, LLC. 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 either in its individual capacity, as opposed to in its capacity as our general partner or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- the exercise of its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;
- its limited call right;
- its voting rights with respect to the units it owns;
- its registration rights; and
- its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder will agree to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common units and subordinated units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty. For example, our partnership agreement:

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the special committee of the board of directors of our general partner 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; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

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 special committee of our general partner or holders of our common units and subordinated units. This may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution) and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of 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 incentive distribution rights.

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 its board of directors, and will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of DCP Midstream GP, LLC, or the General Partner, will be chosen by the members of the General Partner. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they may be unable to remove our general partner without its consent.

The unitholders may be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 662/3% of all outstanding units voting together as a single class is required to remove the general partner. Our general partner and its affiliates own an approximate 43% of our aggregate outstanding common, Class C and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of the general partner because of the unitholder s dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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 or the General Partner from transferring all or a portion of their respective ownership interest in our general partner or the General Partner to a third party. The new owners of our general partner or the General Partner would then be in a position to replace the board of directors and officers of the General Partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

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

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

- our unitholders proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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

DCP Midstream, LLC and its affiliates hold an aggregate of 7,143 common units, 200,312 Class C units, and 7,142,857 subordinated units. The Class C units will automatically convert to common units once the Class C units represent less than 1% of the total outstanding limited partner units. All of the subordinated units will convert into common units at the end of the subordination period, as set forth in our partnership agreement, and some may convert earlier. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner 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. Our general partner and its affiliates own less than 1% of our outstanding common units. At the expiration of the subordination period, assuming no additional issuances of common units, our general partner and its affiliates will own approximately 43% of our outstanding common units.

The liability of holders of limited partner interests 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 a number of 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 other states in which we do business. Holders of limited partner interests could be liable for any and all of our obligations as if such holder 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

- the right of holders of limited partner interests 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 entity-level taxation by individual states. If the Internal Revenue Service treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, which we refer to as the IRS, on this or any other tax matter affecting us.

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

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. If any of these states were to impose a tax on us, the cash available for distribution to the unitholder would be reduced. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

An IRS contest of the federal income tax positions we take may adversely affect the market for our common units, and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. 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.

The unitholder may be required to pay taxes on income from us even if the unitholder does not receive any cash distributions from us.

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

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

If the unitholder sells their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions to the unitholders in excess of the total net taxable income allocated to them for a common unit, which decreased their tax basis in that common unit, will, in effect, become taxable income to them if the common unit is sold at a price greater than their tax basis in that common unit, even if the price is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if the unitholder sells their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

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

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will take depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to the unitholder. 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.

Unitholders may be subject to state and local taxes and return filing requirements.

In addition to federal income taxes, the unitholder may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. The unitholder may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, the unitholder may be subject to penalties for failure to comply with those requirements. We own assets and do business in the States of Louisiana, Texas, Arkansas, New York, Pennsylvania, Ohio, Massachusetts, Vermont, New Hampshire, Rhode Island, Connecticut and Maine. Each of these states, other than Texas, currently imposes a personal income tax as well as an income tax on corporations and other entities. Texas imposes a franchise tax (which is based in part on net income) on corporations and limited liability companies. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in the common units.

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

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

As of March 12, 2007, we operated two processing plants and gathering systems, and one pipeline system located in Louisiana and Arkansas within our Natural Gas Services segment, six propane rail terminals located in the Midwest and northeastern United States within our Wholesale Propane Logistics Segment and two pipelines located in Texas within our NGL Logistics segment, all of which are owned by us. We are also constructing a propane pipeline terminal within our Wholesale Propane Logistics Segment, which is expected to be placed in service in the second quarter of 2007. In addition, we own a 45% interest in the Black Lake pipeline within our NGL Logistics segment, which is operated by a third party, and a 50% interest in a propane rail terminal within our Wholesale Propane Logistics segment. For additional details on these plants, propane terminals and pipeline systems, please read

Business Natural Gas Services Segment, Business Wholesale Propane Logistics Segment and Business NGL Logistics Segment. We believe that our properties are generally in good condition, well maintained and are generally suitable and adequate to carry on our business at capacity for the foreseeable future.

Our principal executive offices are located at 370 17th Street, Suite 2775, Denver, Colorado 80202, and our telephone number is 303-633-2900.

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Item 3. *Legal Proceedings*

We are not a party to any significant legal proceedings but are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows. Please read Business Regulation of Operations and Business Environmental Matters.

In June 2006, a DCP Midstream, LLC customer whose plant is served by our Seabreeze pipeline notified DCP Midstream, LLC that off specification NGLs had been received into their facility. Our Seabreeze pipeline transports NGLs owned by DCP Midstream, LLC that are delivered to the customer under the terms of a transportation agreement. The customer sent a letter to DCP Midstream, LLC claiming that the off specification NGLs delivered to their facility caused damage to their plant facility. On December 29, 2006, we entered into a settlement agreement with the customer to settle all our issues regarding this matter, and our portion of the settlement was $0.3 million.

In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of our general partner, DCP Midstream GP, LP, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which is prior to our acquisition of this asset from DCP Midstream, LLC. El Paso claims damages, including interest, in the amount of $5.7 million in the litigation, the bulk of which stems from audit claims under our commercial contract for historical periods prior to our ownership of this asset. We will only be responsible for potential payments, if any, for claims that involve periods of time after the date we acquired this asset from DCP Midstream, LLC in December 2005. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Item 4. *Submission of Matters to a Vote of Unitholders*

No matters were submitted to a vote of our limited partner unitholders, through solicitation of proxies or otherwise, during the fourth quarter of 2006.

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PART II

Item 5. *Market for Registrant s Common Equity and Related Unitholder Matters*

Market Information

Our common units have been listed on the New York Stock Exchange, or the NYSE, under the symbol DPM since December 2, 2005. Prior to December 2, 2005, our equity securities were not listed on any exchange or traded on any public trading market. The following table sets forth the high and low closing sales prices of the common units, as reported by the NYSE, as well as the amount of cash distributions declared per quarter for 2006 and for the period from December 7, 2005, the closing of our initial public offering, through December 31, 2005.

Quarter Ended	High	Low	Distribution per Common Unit	Distribution per Subordinated Unit
December 31, 2006	$ 35.28	$ 27.90	$ 0.430	$ 0.430
September 30, 2006	$ 28.95	$ 27.48	$ 0.405	$ 0.405
June 30, 2006	$ 29.40	$ 26.40	$ 0.380	$ 0.380
March 31, 2006	$ 28.25	$ 24.05	$ 0.350	$ 0.350
December 7, 2005 to December 31, 2005	$ 24.92	$ 23.08	$ 0.095	$ 0.095

As of March 12, 2007, there were approximately 37 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.

We have also issued 7,142,857 subordinated units, for which there is no established public trading market. The subordinated units are held by our general partner and its affiliates. Our general partner and its affiliates will receive a quarterly distribution on these units only after sufficient funds have been paid to the common units.

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Performance Graph

The following illustrates the comparative total return among DCP Midstream Partners, LP, the Alerian MLP Total Return Index and the S&P 500 Index for the 12 months ended December 31, 2006:

(1) The Alerian MLP total Return Index (NYSE:AMZX) is a composite of the 50 most prominent energy master limited partnerships calculated by Standard & Poor s using a float-adjusted market capitalization methodology.

Issuance of Unregistered Units

On November 1, 2006, we issued to DCP LP Holdings, LP, a wholly-owned subsidiary of DCP Midstream, LLC, 200,312 Class C units as partial consideration for the acquisition of our wholesale propane logistics business. The Class C units were issued to DCP LP Holdings, LP in a private offering conducted in accordance with the exemption from the registration requirements of the securities laws afforded by Section 4(2) of the Securities Act of 1933, as amended. The Class C units will automatically convert to common units once the Class C units represent less than 1% of the total outstanding limited partner units. After two years, if the Class C units are not converted into common units, either automatically or by common unitholder approval, they will receive 115% of the distribution amount for common units. For additional information see Note 12 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

Purchase of Equity by DCP Midstream GP, LP

On November 1, 2006, in order to maintain its 2% general partner interest, DCP Midstream GP, LP purchased 4,088 general partner equivalent units for consideration of $0.1 million.

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending December 31, 2005, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by our general partner.

Definition of Available Cash. Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

less the amount of cash reserves established by our general partner to:

provide for the proper conduct of our business;

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comply with applicable law, any of our debt instruments or other agreements; or

provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;

plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

Minimum Quarterly Distribution. The Minimum Quarterly Distribution, as set forth in the partnership agreement, is $0.35 per unit per quarter, or $1.40 per unit per year. Our current quarterly distribution is $0.43 per unit, or $1.72 per unit annualized. There is no guarantee that we will maintain our current distribution or pay the Minimum Quarterly Distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. We will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under our credit agreement. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Requirements Description of Credit Agreement for a discussion of the restrictions included in our credit agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights. Our general partner is entitled to 2% of all quarterly distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 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 proportionate amount of capital to us to maintain its 2% general partner interest.

Our general partner also currently holds rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute in excess of $0.4025 per unit per quarter. The maximum distribution of 50% includes distributions paid to our general partner on its 2% general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on limited partner units that it owns.

On January 24, 2007, the board of directors of DCP Midstream GP, LLC, declared a quarterly distribution of $0.43 per unit, payable on February 14, 2007, to unitholders of record on February 7, 2007. This distribution resulted in our achieving the second target distribution level pursuant to our partnership agreement. As a result, the distribution in excess of $0.4025 per unit was allocated 85% to all unitholders and 15% to our general partner. For additional information on our distributions see Note 12 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters contained herein.

Item 6. ***Selected Financial Data***

The following table shows our selected financial data for the periods and as of the dates indicated. The selected financial data as of December 31, 2006, 2005, 2004, 2003 and 2002, as well as the selected financial data for the years ended December 31, 2006, 2005 and 2004, are derived from the combined audited consolidated financial statements, which include our accounts, and prior to December 7, 2005, the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries, or DCP Midstream Partners Predecessor, upon the closing of the initial public offering, which have been combined with the historical assets, liabilities and operations of our wholesale propane logistics business, which we acquired from DCP Midstream, LLC in November 2006. This was a transaction among entities under common control; accordingly, our financial information includes the historical results of our wholesale propane logistics business for all periods presented. The selected financial data for the years ended December 31, 2003 and 2002 are derived from the audited consolidated financial statements of the assets, liabilities and operations contributed to us by DCP Midstream Partners Predecessor, and the unaudited consolidated results of operations of the historical assets, liabilities and operations of our wholesale propane logistics business acquired by us from DCP Midstream, LLC in November 2006. The information contained herein should be read together with, and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this Form 10-K.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein to not be indicative of our future financial conditions or results of operations. A discussion on our critical accounting estimates is included in Management s Discussion and Analysis of Financial Condition and Results of Operations.

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The table should also be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	($ in millions, except per unit data)				
Statements of Operations Data:					
Total operating revenues	$ 795.8	$ 1,144.3	$ 834.0	$ 765.7	$ 553.3
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	700.4	1,047.3	760.6	706.1	499.3
Operating and maintenance expense	23.7	22.4	19.8	18.3	17.2
Depreciation and amortization expense	12.8	12.7	14.7	15.5	14.9
General and administrative expense	21.0	14.2	8.7	9.5	7.4
Net gain on sale of assets					(0.1)
Total operating costs and expenses	757.9	1,096.6	803.8	749.4	538.7
Operating income	37.9	47.7	30.2	16.3	14.6
Interest income	6.3	0.5			
Interest expense	(11.5)	(0.8)			
Earnings from equity method investments	0.3	0.4	0.6	0.4	0.5
Impairment of equity method investment(a)			(4.4)		
Income tax expense(b)		(3.3)	(2.5)	(3.6)	(1.1)
Net income	$ 33.0	$ 44.5	$ 23.9	$ 13.1	$ 14.0
Less:					
Net loss (income) attributable to predecessor operations(c)	2.3	(39.8)	(23.9)	(13.1)	(14.0)
General partner interest in net income	(0.7)	(0.1)			
Net income allocable to limited partners	$ 34.6	$ 4.6	$	$	$
Net income per limited partner unit-basic and diluted	$ 1.90	$ 0.20	$	$	$
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 194.7	$ 178.7	$ 179.3	$ 189.6	$ 201.8
Total assets	$ 501.6	$ 529.9	$ 331.4	$ 329.9	$ 339.7
Accounts payable	$ 117.3	$ 138.3	$ 63.5	$ 62.3	$ 60.7
Long-term debt	$ 268.0	$ 210.1	$	$	$ 0.1
Partners equity	$ 103.4	$ 170.5	$ 259.4	$ 257.6	$ 270.0
Other Information:					
Cash distributions declared per unit	$ 1.565	$ 0.095	N/A	N/A	N/A
Cash distributions paid per unit	$ 1.230	N/A	N/A	N/A	N/A

(a) In 2004, we recorded an impairment of our 50% interest in Black Lake totaling $4.4 million as an impairment of equity method investment.

(b) Income tax expense for 2002 through 2005 is applicable to the results of operations of our wholesale propane logistics business. We incurred no income tax expense in 2006, due to the change in tax status of our wholesale propane logistics business in December 2005. See Note 15 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

(c) Includes the net income attributable to DCP Midstream Partners Predecessor through December 7, 2005, and the net income (loss) attributable to our wholesale propane logistics business prior to the date of our acquisition from DCP Midstream, LLC in November 2006.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our consolidated financial statements and notes included elsewhere in this annual report. We refer to the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries upon the closing of our initial public offering as DCP Midstream Partners Predecessor, which have been combined with the historical assets, liabilities and operations of our wholesale propane logistics business, or GSR, which we acquired from DCP Midstream, LLC in November 2006. We refer to DCP Midstream Partners Predecessor and GSR collectively as our predecessors.

Overview

We are a Delaware limited partnership formed in December 2005 by DCP Midstream, LLC (formerly Duke Energy Field Services, LLC) to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We operate in three business segments:

- our Natural Gas Services segment, which consists of our North Louisiana natural gas gathering, processing and transportation system;
- our Wholesale Propane Logistics segment, which consists of six owned rail terminals, one leased marine terminal, one propane pipeline terminal which is under construction, and access to several open access pipeline terminals; and
- our NGL Logistics segment, which consists of our interests in three NGL pipelines.

The financial information contained herein includes our accounts, and prior to December 7, 2005, the assets, liabilities and operations of DCP Midstream Partners Predecessor. In November, 2006 we acquired our wholesale propane logistics business from DCP Midstream, LLC in a transaction among entities under common control. Accordingly, our financial information includes the historical results of our wholesale propane logistics business for all periods presented. The historical financial statements of DCP Midstream Partners Predecessor included in this annual report and discussed elsewhere herein include DCP Midstream Partners Predecessor s 50% ownership interest in Black Lake Pipe Line Company, or Black Lake. However, effective December 7, 2005, DCP Midstream, LLC retained a 5% interest and we own a 45% interest in Black Lake.

Recent Events

In March 2007, we entered into a definitive agreement to acquire certain gathering and compression assets located in southern Oklahoma from Anadarko Petroleum Corporation for approximately $180.3 million, subject to customary closing conditions and certain regulatory approvals. We paid an earnest deposit of $9.0 million when we entered into this agreement. If Anadarko Petroleum Corporation terminates because we materially breach our representations, warranties or covenants under this agreement, they may retain this earnest deposit as liquidated damages. This deposit will be applied against the purchase price at closing of this transaction, which is expected in the second quarter of 2007. The remaining purchase price is expected to be funded by the issuance of partnership units and by proceeds from our credit facility.

In October 2006, we announced that DCP Midstream, LLC had committed to contribute assets to us in exchange for partnership units and cash valued at approximately $250.0 million. The transaction is targeted for the second quarter of 2007. Identification of the specific assets and the related purchase price, along with the other terms of any specific transaction between DCP Midstream, LLC and us, are subject to the approval of the boards of directors of both us and DCP Midstream, LLC, as well as the special committee of our board of directors.

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Factors That Significantly Affect Our Results

Our results of operations for our Natural Gas Services segment are impacted by increases and decreases in the volume of natural gas that we gather and transport through our systems, which we refer to as throughput volume. Throughput volumes and capacity utilization rates generally are driven by wellhead production and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate.

Our results of operations for our Natural Gas Services segment are also impacted by the fees we receive and the margins we generate. Our processing contract arrangements can have a significant impact on our profitability. Because of the volatility of the prices for natural gas, NGLs and condensate, we have hedged a significant portion of our commodity price risk associated with our gathering and processing arrangements through 2010 with natural gas and crude oil swaps, and a significant portion of our condensate price risk through 2011 with crude oil swaps. With these swaps, we have substantially reduced our exposure to commodity price movements with respect to those volumes under these types of contractual arrangements for this period. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies. Actual contract terms will be 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, NGL and condensate prices, may change as a result of producer preferences, our expansion in regions where some types of contracts are more common and other market factors.

In addition, we have benefited from marketing activities and increased throughput related to atypical and significant differences in natural gas prices at various receipt and delivery points on our Pelico intrastate pipeline system.

Our results of operations for our Wholesale Propane Logistics segment are impacted by our ability to balance our purchases and sales of propane, which may increase our exposure to commodity price risks, and by the impact of weather conditions in the Midwest and northeastern sections of the United States. Our sales of propane may decline when these areas experience periods of milder weather in the winter months, which is when the demand for propane is generally at its highest.

Our results of operations for our NGL Logistics segment are impacted by the throughput volumes of the NGLs we transport on our NGL pipelines. Our NGL pipelines transport NGLs exclusively on a fee basis.

Upon the closing of our initial public offering, DCP Midstream, LLC contributed to us the assets, liabilities and operations reflected in the historical financial statements, other than the accounts receivable and certain retained liabilities of DCP Midstream Partners Predecessor, and a 5% interest in Black Lake, which were not contributed to us. In November, 2006 we acquired our wholesale propane logistics business from DCP Midstream, LLC in a transaction among entities under common control. Accordingly, our financial information includes the historical results of our wholesale propane logistics business for all periods presented. The financial statements of our predecessors do not give effect to various items that affected our results of operations and liquidity following the closing of our initial public offering and the acquisition of our wholesale propane logistics business, including the items described below:

- the indebtedness we incurred in conjunction with the closing of our initial public offering and the acquisition of our wholesale propane logistics business, which increased our interest expense from the interest expense reflected in our historical financial statements;

- we have entered into long-term hedging arrangements for a significant portion of our expected natural gas and NGL commodity price risk relating to our gathering and processing arrangements through 2010, and for a significant portion of our expected condensate commodity price risk through 2011; and

the incremental general and administrative expenses relating to operating as a separate publicly held limited partnership. These incremental expenses include compensation and benefit expenses of the personnel who provide direct support to our operations, costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation. Additionally, we incur expenses pursuant to the Omnibus Agreement, as amended, for other various general and administrative services provided by DCP Midstream, LLC.

We completed pipeline integrity testing during 2006, resulting in increased operating costs on Seabreeze, one of our NGL transportation pipelines. The construction of Wilbreeze, an NGL transportation pipeline connecting a DCP Midstream, LLC gas processing plant to the Seabreeze pipeline, was completed in December 2006. We expect to see increased throughput volume from DCP Midstream, LLC of approximately 5,300 barrels per day, or Bbls/d. The Black Lake pipeline is currently experiencing increased operating costs due to pipeline integrity testing that commenced in 2005 and has continued into 2007. We expect that our results of operations related to our equity interest in the Black Lake pipeline will benefit in 2007 from the completion of this pipeline integrity testing, although it is possible that the integrity testing will result in the need for pipeline repairs, in which case the operations of this pipeline may be interrupted while the repairs are being made. DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing, and up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of the pipeline integrity testing. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Any reimbursement of these expenses from DCP Midstream, LLC will be recognized by us as a capital contribution. Reimbursements related to the Seabreeze pipeline integrity repairs in 2006 were not significant.

During 2006, we entered into agreements with ConocoPhillips, which expanded the gathering and transportation services between us. As a result of these agreements, 17 new wells were added to our system during 2006, with additional volumes possible over the next three years.

Finally, we intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures.

General Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Natural Gas Supply and Outlook We believe that current natural gas prices will continue to cause relatively strong levels of natural gas-related drilling in the United States as producers seek to increase their level of natural gas production. Although the number of natural gas wells drilled in the United States has increased overall in recent years, a corresponding increase in production has not been realized, primarily as a result of smaller discoveries and the decline in production from existing wells. We believe that an increase in United States drilling activity, additional sources of supply such as liquified natural gas, and imports of natural gas will be required for the natural gas industry to meet the expected increased demand for, and to compensate for the slowing production of, natural gas in the United States. A number of the areas in which we operate are experiencing significant drilling activity, new increased drilling for deeper natural gas formations, and the implementation of new exploration and production techniques.

While we anticipate continued high levels of exploration and production activities in a number of the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new natural gas reserves. Drilling activity generally decreases as natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations.

Wholesale Propane Supply and Outlook We are a wholesale supplier of propane for the Midwest and northeastern United States, which consists of New York, Pennsylvania, Ohio, Massachusetts, Vermont, New Hampshire, Rhode Island, Connecticut and Maine. Pipeline deliveries to this region in the winter season are generally at capacity and competing propane supply sources, generally consisting of open access propane terminals supplied by interstate pipelines, can have significant supply constraints or outages during peak market conditions. Due to our multiple propane supply sources, propane supply contractual arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our retail propane distribution customers with reliable deliveries of propane during periods of tight supply, such as the winter months when their retail customers consume the most propane for home heating.

We manage our wholesale propane margins by selling propane to retail propane distributors under annual sales agreements negotiated each spring. These agreements specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year, and we manage this commodity price risk by entering into either offsetting physical purchase agreements or financial derivate instruments, with either DCP Midstream, LLC or third parties, that generally match the quantities of propane subject to these fixed price sales agreements. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

Processing Margins Our processing profitability is dependent upon pricing and market demand for natural gas, NGLs and condensate, which are beyond our control and have been volatile. We have mitigated our exposure to commodity price movements for these commodities by entering into hedging arrangements for a significant portion of our currently anticipated natural gas and NGL price risk through 2010 associated with our percentage-of-proceeds arrangements, and our operations through 2011 associated with condensate recovered from our gathering operations. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

Falling Commodity Prices During the aftermath of hurricanes Katrina and Rita, which negatively affected the nation s short term energy supply in the latter part of 2005, natural gas, NGL and condensate prices experienced a significant increase. Prices for these commodities have since decreased.

Impact of Inflation Our industry has experienced rising inflation due to increased activity in the energy sector. Consequently, our costs for chemicals, utilities, materials and supplies, contract labor and major equipment purchases have increased. In the future, we may continue to be affected by inflation. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Our Operations

We manage our business and analyze and report our results of operations on a segment basis. Our operations are divided into our Natural Gas Services segment, our Wholesale Propane Logistics segment and our NGL Logistics segment.

Natural Gas Services Segment

Results of operations from our Natural Gas Services segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our gathering, processing and pipeline systems; the volumes of NGLs and condensate sold; and the level of our realized natural gas, NGL and condensate prices. We generate our revenues and our gross margin for our Natural Gas Services segment principally under fee-based arrangements and percentage-of-proceeds arrangements, as described below in Critical Accounting Policies and Estimates Revenue Recognition.

We have hedged a significant portion of our currently anticipated natural gas and NGL commodity price risk associated with the percentage-of-proceeds arrangements through 2010 with natural gas and crude oil swaps. With these swaps, we expect our exposure to commodity price movements to be substantially reduced. Additionally, as part of our gathering operations, we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices. We have hedged a significant portion of our condensate price risk through 2011 with crude oil swaps. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

We also purchase a small portion of our natural gas under percentage-of-index arrangements. Under percentage-of-index arrangements, we purchase natural gas from the producers at the wellhead at a price that is either at a fixed percentage of the index price for the natural gas that they produce, or at an index based price less a fixed fee to gather, compress, treat and/or process their natural gas. We then gather, compress, treat and/or process the natural gas and then sell the residue natural gas and NGLs at index related prices. Under these types of arrangements, our cost to purchase the natural gas from the producer is based on the price of natural gas. As a result, our gross margin under these arrangements increases as the price of NGLs increases relative to the price of natural gas, and our gross margin under these arrangements decreases as the price of natural gas increases relative to the price of NGLs.

The natural gas supply for the gathering pipelines and processing plants in our North Louisiana system is derived primarily from natural gas wells located in five parishes in northern Louisiana. The Pelico system also receives natural gas produced in east Texas through its interconnect with other pipelines that transport natural gas from east Texas into western Louisiana. This five parish area has experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. Our primary suppliers of natural gas to the North Louisiana system are Anadarko Petroleum Corporation and ConocoPhillips (one of our affiliates), which collectively represented approximately 60% of the 312 MMcf/d of natural gas supplied to this system in 2006. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been released from other gathering systems.

We sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. In addition, under our merchant arrangements, we use DCP Midstream, LLC as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties. We also have entered into a contractual arrangement with DCP Midstream, LLC that provides that DCP Midstream, LLC will purchase natural gas and transport it into our Pelico system, where we will buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. In addition, for a significant portion of the gas that we sell out of our Pelico system, we have entered into a contractual arrangement with DCP Midstream, LLC that provides that DCP Midstream, LLC will purchase that natural gas from us and transport it to a sales point at a price equal to their net weighted-average sales price less a contractually agreed-to marketing fee. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index. We account for such a physical fixed price transaction and the related financial derivative as a fair value hedge. We occasionally will enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting. We also gather, process and transport natural gas under fee-based transportation contracts.

The NGLs extracted from the natural gas at the Minden processing plant are sold at market index prices to an affiliate of DCP Midstream, LLC and transported to the Mont Belvieu hub via the Black Lake pipeline.

The NGLs extracted from the natural gas at the Ada processing plant are sold at market index prices to affiliates.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the Midwest and northeastern United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Midwest and the northeastern areas of the United States. We sell propane on a wholesale basis to retail propane distributors who in turn resell propane to their retail customers.

Due to our multiple propane supply sources, long-term propane supply purchase arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our retail propane distribution customers with reliable deliveries of propane during periods of tight supply, such as the winter months when their retail customers consume the most propane for home heating. In particular, we generally offer our customers the ability to obtain propane supply volumes from us in the winter months that are significantly greater than their purchase of propane from us in the summer. We believe these factors generally allow us to maintain our favorable relationship with our customers.

We manage our wholesale propane margins by selling propane to retail propane distributors under annual sales agreements negotiated each spring that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year, and we manage this commodity price risk by entering into either offsetting physical purchase agreements or financial derivative instruments, with either DCP Midstream, LLC or third parties, that generally match the quantities of propane subject to these fixed price sales agreements. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

NGL Logistics Segment

Historically, we have gathered and transported NGLs either under fee-based transportation contracts, or through purchasing the NGLs at the inlet of the pipeline and selling the NGLs at the outlet. In conjunction with our formation, we entered into a contractual arrangement with DCP Midstream, LLC that requires DCP Midstream, LLC to purchase the NGLs that were historically purchased by us, and to pay us to transport the NGLs pursuant to a fee-based rate that is applied to the volumes transported. We entered into this fee-based contractual arrangement with the objective of generating approximately the same operating income per barrel transported that we realized when we were the purchaser and seller of NGLs.

Our pipelines provide transportation services to customers on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines; rather, the shipper retains title and the associated commodity price risk. For the Seabreeze and Wilbreeze pipelines, we are responsible for any line loss or gain in NGLs. For the Black Lake pipeline, any line loss or gain in NGLs is allocated to the shipper. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the mixed NGLs from the natural gas. As a result, we have experienced periods in the past, and will likely experience periods in the future, in which higher natural gas prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets. In the markets we serve, our pipelines are the sole pipeline facility transporting NGLs from the supply source.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes; (2) gross margin, including segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) EBITDA; and (5) distributable cash flow. Gross margin, segment gross margin, EBITDA and distributable cash flow measurements are not accounting principles generally accepted in the United States of America, or GAAP, financial measures. We provide reconciliations of these non-GAAP measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. Our gross margin, segment gross margin, EBITDA and distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

Volumes We view throughput volumes on our North Louisiana system and our NGL pipelines, and sales volumes in our wholesale propane business as an important factor affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of the North Louisiana system s natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by: (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines; and (2) our ability to compete for volumes from successful new wells in other areas. The throughput volumes of NGLs on our pipelines are substantially dependent upon the quantities of NGLs produced at our processing plants, as well as NGLs produced at other processing plants that have pipeline connections with the NGL pipelines. We regularly monitor producer activity in the areas served by the North Louisiana system and our pipelines, and pursue opportunities to connect new supply to these pipelines.

Gross Margin We view our gross margin as an important performance measure of the core profitability of our operations. We review our gross margin monthly for consistency and trend analysis.

We define gross margin as total operating revenues less purchases of natural gas, propane and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases for that segment. Our gross margin equals the sum of our segment gross margins. Gross margin is included as a supplemental disclosure because it is a primary performance measure used by management, as it represents the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

With respect to our Natural Gas Services segment, we calculate our gross margin as our total operating revenue for this segment less natural gas and NGL purchases. Operating revenue consists of sales of natural gas, NGLs and condensate resulting from our gathering, compression, treating, processing and transportation activities, fees associated with the gathering of natural gas, and any gains and losses realized from our non-trading derivative activity related to our natural gas asset-based marketing. Purchases include the cost of natural gas and NGLs purchased by us. Our gross margin is impacted by our contract portfolio. We purchase the wellhead natural gas from the producers under percentage-of-proceeds arrangements or percentage-of-index arrangements. Our gross margin generated from percentage-of-proceeds gathering and processing contracts is directly correlated to the price of natural gas and NGLs. Under percentage-of-index arrangements, our gross margin is adversely affected when the price of NGLs falls in relation to the price of natural gas. Generally, our contract structure allows for us to allocate fuel costs and other measurement losses to the producer or shipper and, therefore, does not impact gross margin. Additionally, as part of our gathering operations, we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices.

Our gross margin and segment gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin and segment gross margin in the same manner.

Reconciliation of Non-GAAP Measures	Year Ended December 31, 2006	2005	2004
	($ in millions)		
Reconciliation of net income to gross margin:			
Net income	$ 33.0	$ 44.5	$ 23.9
Add:			
Interest expense	11.5	0.8	
Impairment of equity method investment			4.4
Income tax expense		3.3	2.5
Operating and maintenance expense	23.7	22.4	19.8
Depreciation and amortization expense	12.8	12.7	14.7
General and administrative expense	21.0	14.2	8.7
Less:			
Interest income	6.3	0.5	
Earnings from equity method investments	0.3	0.4	0.6
Gross margin	$ 95.4	$ 97.0	$ 73.4
Reconciliation of segment net income (loss) to segment gross margin:			
Natural Gas Services segment:			
Segment net income	$ 50.7	$ 46.6	$ 28.5
Add:			
Depreciation and amortization expense	11.1	10.8	11.7
Operating and maintenance expense	13.5	14.0	13.4
Segment gross margin	$ 75.3	$ 71.4	$ 53.6
Wholesale Propane Logistics segment:			
Segment net income	$ 6.6	$ 12.6	$ 8.2
Add:			
Depreciation and amortization expense	0.8	1.0	2.1
Operating and maintenance expense	8.6	8.2	6.2
Segment gross margin	$ 16.0	$ 21.8	$ 16.5
NGL Logistics segment:			
Segment net income (loss)	$ 1.9	$ 3.1	$ (1.6)
Add:			
Depreciation and amortization expense	0.9	0.9	0.9
Operating and maintenance expense	1.6	0.2	0.2
Impairment of equity method investment			4.4
Less: Earnings from equity method investments	(0.3)	(0.4)	(0.6)

Segment gross margin	$ 4.1	$ 3.8	$ 3.3

Operating and Maintenance and General and Administrative Expense Operating and maintenance expense are costs associated with the operation of a specific asset. Direct labor, ad valorem taxes, repairs and maintenance, lease expenses, utilities and contract services comprise the most significant portion of our operating and maintenance expense. These expenses are relatively independent of the volumes through our systems, but may fluctuate slightly depending on the activities performed during a specific period.

A substantial amount of our general and administrative expense is incurred through DCP Midstream, LLC. For the years ended December 31, 2006, 2005 and 2004, our general and administrative expense was $21.0 million, $14.2 million and $8.7 million, respectively.

We have entered into the Omnibus Agreement with DCP Midstream, LLC. Under the Omnibus Agreement, as amended, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee of $4.8 million for services provided on our behalf related to the DCP Midstream Predecessor business contributed to us upon our initial public offering. The annual fee is for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The Omnibus Agreement, as amended: (1) clarifies that the annual fee of $4.8 million under the agreement is fixed at such amount, subject to annual increases in the Consumer Price Index, and increases in connection with the expansion of our operations through the acquisition or construction of new assets or businesses; and (2) effective November 2006, includes an additional annual fee of $2.0 million related to the acquisition of our wholesale propane logistics business from DCP Midstream, LLC, subject to the same conditions noted above. We recognized $0.3 million of the additional $2.0 million fee in 2006 related to our wholesale propane logistics business acquisition.

The Omnibus Agreement addresses the following matters:

- our obligation to reimburse DCP Midstream, LLC for the payment of operating expenses, including salary and benefits of operating personnel, it incurs on our behalf in connection with our business and operations;

- our obligation to reimburse DCP Midstream, LLC for providing us with general and administrative services with respect to our business and operations;

- our obligation to reimburse DCP Midstream, LLC for insurance coverage expenses it incurs with respect to our business and operations and with respect to director and officer liability coverage;

- DCP Midstream, LLC s obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities;

- DCP Midstream, LLC s obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements were in effect as of the closing of our initial public offering until the earlier to occur of the fifth anniversary of the closing of our initial public offering or such time as we obtain an investment grade credit rating from either Moody s Investor Services, Inc. or Standard & Poor s Ratings Group with respect to any of our unsecured indebtedness; and

- DCP Midstream, LLC s obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts.

Under our Omnibus Agreement with DCP Midstream, LLC, as amended, we will reimburse DCP Midstream, LLC $7.0 million for 2007, for the provision by DCP Midstream, LLC or its affiliates of various general and administrative services to us. For 2008, the fee will be increased by the percentage increase in the Consumer Price Index for the applicable year. In addition, our general partner will have the right to agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses, with the concurrence of the special committee of DCP Midstream GP, LLC s board of directors.

We incurred approximately $15.9 million, $13.9 million and $8.7 million of other general and administrative expense during the years ending December 31, 2006, 2005 and 2004, respectively, relating to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation. These incremental expenses exclude $5.1, $0.3 million and $0 million for the years ended December 31, 2006, 2005 and 2004, respectively, per the Omnibus Agreement, as amended, for other various general and administrative services.

EBITDA and Distributable Cash Flow We define EBITDA as net income less interest income, plus interest expense, income tax expense and depreciation and amortization expense. EBITDA is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures. EBITDA is also a financial measurement that is reported to our lenders, and used as a gauge for compliance with our financial covenants under our credit facility, which requires us to maintain: (1) a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the 5-year credit agreement, or the Credit Agreement) of not more than 4.75 to 1.0, and on a temporary basis for not more than three consecutive quarters following the consummation of asset acquisitions in the midstream energy business, of not more than 5.25 to 1.0; and (2) an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Credit Agreement) of greater than or equal to 3.0 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination. Our EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA in the same manner.

EBITDA is also used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- 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 those of other companies in the midstream energy industry, without regard to financing methods or capital structure; and
- viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

We define distributable cash flow as EBITDA, plus interest income, less interest expense, maintenance capital expenditures, net of reimbursable projects, earnings from equity method investment and adjustments for non-cash hedge ineffectiveness (see Liquidity and Capital Resources for further definition of maintenance capital expenditures). In 2006, we also adjusted distributable cash flow for a post-closing reimbursement from DCP Midstream, LLC for maintenance capital expenditures. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining the existing system volumes and related cash flows. Non-cash hedge ineffectiveness refers to the ineffective portion of our cash flow hedges, which is recorded in earnings in the current period. This amount is considered to be non-cash for the purpose of computing distributable cash flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices. Distributable cash flow is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and other, to assess our ability to make cash distributions to our unitholders and our general partner.

Reconciliation of Non-GAAP Measures	Year Ended December 31, 2006	2005	2004
	($ in millions)		
Reconciliation of net income to EBITDA:			
Net income	$ 33.0	$ 44.5	$ 23.9
Interest income	(6.3)	(0.5)	
Interest expense	11.5	0.8	
Income tax expense		3.3	2.5
Depreciation and amortization expense	12.8	12.7	14.7
EBITDA	$ 51.0	$ 60.8	$ 41.1
Reconciliation of net cash provided by operating activities to EBITDA:			
Net cash provided by operating activities	$ 68.9	$ 76.3	$ 24.7
Interest income	(6.3)	(0.5)	
Interest expense	11.5	0.8	
Earnings from equity method investments	0.3	0.4	0.6
Income tax expense		3.3	2.5
Non-cash impairment of equity method investment			(4.4)
Net changes in operating assets and liabilities	(25.8)	(19.9)	17.4
Other, net	2.4	0.4	0.3
EBITDA	$ 51.0	$ 60.8	$ 41.1

Critical Accounting Policies and Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make estimates and assumptions. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Revenue Recognition We generate the majority of our revenues from: (1) sales of natural gas, propane, NGLs and condensate; (2) natural gas gathering, processing and transportation, from which we generate revenue primarily through the compression, gathering, treating, processing and transportation of natural gas; (3) NGL transportation from which we generate revenues from transportation fees; as well as (4) trading and marketing of natural gas and NGLs.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following arrangements:

> *Fee-based arrangements* Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing or transporting natural gas; and transporting NGLs. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead or other receipt points, at an index related price at the delivery point less a specified

amount, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues from these arrangements would be reduced.

Percentage-of-proceeds arrangements Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, transport the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs at index prices based on published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Under these types of arrangements, our revenues correlate directly with the price of natural gas and NGLs.

Propane sales arrangements Under propane sales arrangements, we generally purchase propane from natural gas processing plants and fractionation facilities, and crude oil refineries. We sell propane on a wholesale basis to retail propane distributors, who in turn resell to their retail customers. Our sales of propane are not contingent upon the resale of propane by propane distributors to their retail customers.

Our marketing of natural gas and NGLs consists of physical purchases and sales, as well as positions in derivative instruments.

We recognize revenues for sales and services under the four revenue recognition criteria, as follows:

Persuasive evidence of an arrangement exists Our customary practice is to enter into a written contract, executed by both us and the customer.

Delivery Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.

The fee is fixed or determinable We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.

Collectability is probable Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers financial position (for example, cash position and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is recognized when the fee is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody to the product, and incur the risks and rewards of ownership. We recognize revenues for non-trading derivative activity net in the consolidated statements of operations. Effective April 1, 2006, any new or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues from non-trading derivative activity net in the consolidated statements of operations as gains (losses) from non-trading derivative activity. These activities include mark-to-market gains and losses on energy trading contracts, and the financial or physical settlement of energy trading contracts.

Inventories Inventories, which consist primarily of propane, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

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

Goodwill Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess.

Impairment of Long-Lived Assets We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse changes in legal factors or in the business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset s carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management s intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Impairment of Equity Method Investments We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate, in management s judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. If the estimated fair value is less than the carrying value and we consider the decline in value to be other than temporary, we recognize an impairment for the excess of the carrying value over the estimated fair value.

Accounting for Risk Management and Hedging Activities and Financial Instruments Each derivative not qualifying for the normal purchases and normal sales exception under Statement of Financial Accounting Standards, or SFAS, No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, or SFAS 133, is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging instruments at fair value until the contractual settlement period impacts earnings.

We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activities, are designated as non-trading activity. For a complete discussion of our hedging policies, see Note 2 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

When available, quoted market prices or prices obtained through external sources are used to determine a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Accounting for Equity-Based Compensation We adopted a long-term incentive plan, which permits for the grant of restricted units, phantom units, unit options and substitute awards, as described further in Note 2 and Note 14 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. Equity-based compensation expense is accounted for under the provisions of SFAS No. 123 (Revised 2004), *Share-Based Payment*, over the vesting period of the related awards. We estimate the fair value of each award, and the number of awards that will ultimately vest at the end of each service period. These estimates are based on the tenure of our employees and the achievement of certain performance targets over the performance period. If actual results are not consistent with our assumptions and judgments, we may experience material changes in compensation expense.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2006. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year Ended December 31,		
	2006	2005	2004
	($ in millions except operating data)		
Operating revenues:			
Natural Gas Services	$ 415.3	$ 592.8	$ 353.3
Wholesale Propane Logistics	375.2	359.8	324.5
NGL Logistics	5.3	191.7	156.2
Total operating revenues	795.8	1,144.3	834.0
Gross margin(a):			
Natural Gas Services	75.3	71.4	53.6
Wholesale Propane Logistics	16.0	21.8	16.5
NGL Logistics	4.1	3.8	3.3
Total gross margin	95.4	97.0	73.4
Operating and maintenance expense	23.7	22.4	19.8
General and administrative expense	21.0	14.2	8.7
Earnings from equity method investments(b)	(0.3)	(0.4)	(0.6)
Impairment of equity method investment(c)			4.4
EBITDA(d)	51.0	60.8	41.1
Depreciation and amortization expense	12.8	12.7	14.7
Interest income	(6.3)	(0.5)	
Interest expense	11.5	0.8	
Income tax expense		3.3	2.5
Net income	$ 33.0	$ 44.5	$ 23.9
Operating data:			
Natural gas throughput (MMcf/d)	385	356	328
NGL gross production (Bbls/d)	5,273	4,543	4,690
Propane sales volume (Bbls/d)	21,259	22,604	24,589
NGL pipelines throughput (Bbls/d)(b)	25,040	20,565	20,222

(a) Gross margin consists of total operating revenues less purchases of natural gas, propane and NGLs, and segment gross margin for each segment consists of total operating revenues for that segment, less commodity purchases for that segment. Please read How We Evaluate Our Operations above.

(b) Includes 45% of the throughput volumes and earnings of Black Lake in 2006 and the period from December 7, 2005 through December 31, 2005. Prior to December 7, 2005, we owned a 50% interest in Black Lake.

(c) Represents an impairment of our equity interest in Black Lake.

(d) EBITDA consists of net income less interest income plus interest expense, income tax expense, and depreciation and amortization expense. Please read How We Evaluate Our Operations above.

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Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues Total operating revenues decreased $348.5 million, or 30%, to $795.8 million in 2006 from $1,144.3 million in 2005, primarily due to the following:

$190.3 million decrease primarily attributable to lower sales for our Seabreeze pipeline, primarily due to a change in contract terms in December 2005, between DCP Midstream, LLC and us, from a purchase and sale arrangement to a fee-based contractual transportation arrangement for our NGL Logistics segment; and

$181.3 million decrease attributable primarily to lower natural gas prices and sales volumes, and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation, partially offset by an increase in NGL and condensate prices and sales volumes for our Natural Gas Services segment; offset by

$15.2 million increase attributable to higher propane prices, which were offset by lower sales volumes for our Wholesale Propane Logistics segment;

$4.7 million increase in transportation revenue primarily attributable to an increase in volumes and a change in contract terms in December 2005 for our Seabreeze pipeline, from a purchase and sale arrangement to a fee-based contractual transportation arrangement; and

$3.2 million increase related to commodity hedging and non-trading derivative activity.

Gross Margin Gross margin decreased $1.6 million, or 2%, to $95.4 million in 2006 from $97.0 million in 2005, primarily due to the following:

$5.8 million decrease due to non-cash lower of cost or market inventory adjustments, decreased sales volumes, and increased product and transportation costs for our Wholesale Propane Logistics segment; offset by

$3.9 million increase for our Natural Gas Services segment primarily due to higher NGL and condensate prices, and an increase in natural gas throughput volumes, offset by lower natural gas prices, decreases due to a change in contract mix, and decreased marketing activity and throughput across the Pelico system due to atypical differences in natural gas prices at various receipt and delivery points across the system, which impacted gross margin more significantly in 2005 than in 2006. The market conditions causing the differentials in natural gas prices at various receipt and delivery points may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and

$0.3 million increase attributable to increased transportation revenue and higher volumes on our Seabreeze pipeline for our NGL Logistics segment.

Operating and Maintenance Expense Operating and maintenance expense increased $1.3 million, or 6%, to $23.7 million in 2006 from $22.4 million in 2005, primarily as a result of higher pipeline integrity costs, increased labor and benefit costs, an increase in lease expense and the settlement of a commercial dispute.

General and Administrative Expense General and administrative expense increased $6.8 million, or 48%, to $21.0 million in 2006 from $14.2 million in 2005, primarily as a result of increased audit fees, due diligence and acquisition costs, costs incurred related to the Sarbanes-Oxley Act of 2002, labor and benefit costs, and insurance premiums.

Earnings from Equity Method Investments Earnings from equity method investments were relatively constant in 2006 and 2005.

Depreciation and Amortization Expense Depreciation and amortization expense was relatively constant in 2006 and 2005.

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Income Tax Expense We incurred no income tax expense in 2006, due to the change in tax status of our wholesale propane logistics business in December 2005. See Note 15 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues Total operating revenues increased $310.3 million, or 37%, to $1,144.3 million in 2005 from $834.0 million in 2004, primarily due to the following:

$237.4 million increase attributable primarily to higher commodity prices and natural gas sales volumes for our Natural Gas Services segment;

$35.2 million increase primarily attributable to higher NGL prices and increased throughput for our Seabreeze pipeline;

$34.1 million increase attributable primarily to higher propane prices, which were partially offset by lower sales volumes for our Wholesale Propane Logistics segment;

$2.6 million increase in transportation revenue; and

$1.0 million increase related to commodity hedging, and non-trading derivative activity.

Gross Margin Gross margin increased $23.6 million, or 32%, to $97.0 million in 2005 from $73.4 million in 2004, primarily as a result of the following:

$17.8 million increase attributable primarily to higher commodity prices and an increase in marketing activity and increased throughput across the Pelico system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system for our Natural Gas Services segment. The market conditions causing these significant differences in the natural gas prices at various receipt and delivery points across the Pelico system are unusual and may not continue in the future, and we may not be able to capture the upside related to this market condition in the future;

$5.3 million increase due to increased prices and an increase related to commodity hedging, partially offset by lower sales volumes and increased product and transportation costs for our Wholesale Propane Logistics segment; and

$0.5 million increase due to increased throughput volumes for our Seabreeze pipeline.

Impact of Hurricanes Katrina and Rita Hurricanes Katrina and Rita caused extensive damage to the Texas, Louisiana and Mississippi Gulf Coast in late August and mid-September of 2005. These storms did not cause any significant damage to our properties. However, in September 2005, we experienced operational disruptions for several days as a result of the impact of Hurricane Rita on the energy industry in our areas of operations. These disruptions reduced our total operating revenues by approximately $10.1 million, our purchases by approximately $9.5 million and our gross margin by approximately $0.6 million in September 2005.

Operating and Maintenance Expense Operating and maintenance expense increased $2.6 million, or 13%, to $22.4 million in 2005 from $19.8 million in 2004, primarily as a result of higher pipeline integrity costs, higher maintenance expenses, increased labor costs and higher lease expenses.

General and Administrative Expense General and administrative expense increased $5.5 million, or 63%, to $14.2 million in 2005 from $8.7 million in 2004. This increase was primarily the result of public offering costs of approximately $4.0 million and higher allocated costs from DCP Midstream, LLC for general and administrative costs, primarily as a result of increased insurance premiums.

Earnings from Equity Method Investments Earnings from equity method investments decreased $0.2 million, to $0.4 million in 2005 from $0.6 million in 2004, primarily due to an increase in Black Lake operating costs as a result of pipeline integrity testing during the fourth quarter of 2005.

Impairment of Equity Method Investment In 2004, we recorded an impairment totaling $4.4 million of our equity interest in Black Lake, which is included in the NGL Logistics segment.

Depreciation and Amortization Expense Depreciation and amortization expense decreased $2.0 million, or 14%, to $12.7 million in 2005 from $14.7 million in 2004 as a result of certain assets that became fully depreciated at the beginning of 2005.

Results of Operations Natural Gas Services Segment

This segment consists of our North Louisiana system, which includes our Pelico system and our Minden and Ada processing plants and gathering systems.

	Year Ended December 31,		
	2006	2005	2004
	($ in millions except operating data)		
Operating revenues:			
Sales of natural gas, NGLs and condensate	$ 391.8	$ 570.9	$ 333.5
Transportation and processing services	23.5	22.6	19.9
Losses from non-trading derivative activity		(0.7)	(0.1)
Total operating revenues	415.3	592.8	353.3
Purchases of natural gas and NGLs	340.0	521.4	299.7
Segment gross margin(a)	75.3	71.4	53.6
Operating and maintenance expense	13.5	14.0	13.4
Depreciation and amortization expense	11.1	10.8	11.7
Segment net income	$ 50.7	$ 46.6	$ 28.5
Operating data:			
Natural gas throughput (MMcf/d)	385	356	328
NGL gross production (Bbls/d)	5,273	4,543	4,690

(a) Segment gross margin consists of total operating revenues less purchases of natural gas and NGLs. Please read How We Evaluate Our Operations above.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues Total operating revenues decreased $177.5 million, or 30%, to $415.3 million in 2006 from $592.8 million in 2005, primarily due to the following:

$114.1 million decrease attributable to a decrease in natural gas sales volumes and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation; and

$87.3 million decrease attributable to a decrease in natural gas prices; offset by

$10.1 million increase primarily attributable to higher NGL and condensate sales volumes;

$10.0 million increase attributable to an increase in NGL and condensate prices;

$2.9 million increase related to commodity hedging and non-trading derivative activity; and

$0.9 million increase in transportation revenue primarily attributable to an increase in natural gas throughput.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased $181.4 million, or 35%, to $340.0 million in 2006 from $521.4 million in 2005, primarily due to lower costs of raw natural gas supply, driven by lower natural gas prices and decreased purchased volumes, and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation, partially offset by higher NGL and condensate prices and NGL and condensate purchased volumes.

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Segment Gross Margin Segment gross margin increased $3.9 million, or 5%, to $75.3 million in 2006 from $71.4 million in 2005, primarily as a result of the following:

$6.2 million increase attributable to higher NGL and condensate prices and favorable frac spreads, partially offset by lower natural gas prices. The frac spreads that existed during 2006 were higher than in recent years and may not continue in the future;

$5.2 million increase primarily attributable to an increase in natural gas throughput volumes;

$2.9 million increase related to commodity hedging and non-trading derivative activity; and

$0.5 million increase attributable to higher contractual fees charged to customers related to pipeline imbalances; offset by

$5.1 million decrease primarily attributable to a change in contract mix;

$4.0 million decrease attributable to a decrease in marketing activity and throughput across our Pelico system due to atypical differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and

$1.8 million decrease attributable to higher netback prices paid to the producers at Minden and Ada.

Operating and Maintenance Expense Operating and maintenance expense decreased $0.5 million, or 4%, to $13.5 million in 2006 from $14.0 million in 2005, primarily as a result of lower costs associated with repairs and maintenance.

NGL production during 2006 increased 730 Bbls/d, or 16%, to 5,273 Bbls/d from 4,543 Bbls/d in 2005, due primarily to unfavorable market economics for processing NGLs in the fourth quarter of 2005. Natural gas transported and/or processed during 2006 increased 29 MMcf/d, or 8%, to 385 MMcf/d from 356 MMcf/d in 2005, primarily as a result of higher natural gas volumes for our Pelico system.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues Total operating revenues increased $239.5 million, or 68%, to $592.8 million in 2005 from $353.3 million in 2004, primarily due to the following:

$169.6 million increase attributable to an increase in natural gas prices;

$15.0 million increase attributable to an increase in NGL and condensate prices;

$52.8 million increase attributable to higher natural gas sales volumes driven primarily by incremental natural gas demand at our Minden and Ada processing plants related to our merchant arrangements, higher gas supply volumes for our Ada processing plant and gathering system and an increase in marketing activity and increased throughput across the Pelico system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing these significant differences in the natural gas prices at various receipt and delivery points across the Pelico system are unusual and may not continue in the future, and we may not be able to capture the upside related to the market condition in the future; and

$2.7 million increase attributable to higher processing fees primarily driven by incremental fee-based services of our Ada gathering system and higher transportation fees primarily driven by an increase in volumes on our Pelico system; offset by

$0.6 million decrease attributable to lower non-trading derivative activity.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased $221.7 million, or 74%, to $521.4 million in 2005 from $299.7 million in 2004, primarily due to higher costs of raw natural gas supply driven by higher commodity prices.

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Segment Gross Margin Segment gross margin increased $17.8 million, or 33%, to $71.4 million in 2005 from $53.6 million in 2004, primarily as a result of the following:

$9.3 million increase attributable to an increase in marketing activity and increased throughput across the Pelico system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur;

$8.7 million increase attributable to higher commodity prices; and

$2.7 million increase attributable to higher processing fees primarily driven by incremental fee-based services of our Ada gathering system and higher transportation fees primarily driven by an increase in volumes on our Pelico system; offset by

$2.3 million decrease attributable to lower contractual fees charged to customers related to pipeline imbalances and a decrease in NGL recoveries at Minden as a result of unfavorable processing economics in the fourth quarter of 2005; and

$0.6 million decrease attributable to lower non-trading derivative activity.

Operating and Maintenance Expense Operating and maintenance expense increased $0.6 million, or 4%, to $14.0 million in 2005 from $13.4 million in 2004, primarily as a result of higher outside services, parts, supplies and labor for maintenance and higher costs for pipeline integrity testing.

NGL production during 2005 decreased 147 Bbls/d, or 3%, to 4,543 Bbls/d from 4,690 Bbls/d in 2004 due primarily to unfavorable market economics for processing NGLs in the fourth quarter of 2005. Natural gas transported and/or processed during 2005 increased 28 MMcf/d, or 9%, to 356 MMcf/d from 328 MMcf/d in 2004, primarily as a result of higher natural gas volumes for our Pelico system.

Results of Operations Wholesale Propane Logistics Segment

This segment includes our propane transportation facilities, which includes six owned propane rail terminals, one leased propane marine terminal, one propane pipeline terminal which is under construction, and access to several open-access propane pipeline terminals.

	Year Ended December 31,		
	2006	**2005**	**2004**
	($ in millions except operating data)		
Operating revenues:			
Sales of propane	$ 375.0	$ 359.8	$ 325.7
Transportation and processing services	0.1	0.2	0.6
Gains (losses) from non-trading derivative activity	0.1	(0.2)	(1.8)
Total operating revenues	375.2	359.8	324.5
Purchases of propane	359.2	338.0	308.0

Segment gross margin(a)	16.0	21.8	16.5
Operating and maintenance expense	8.6	8.2	6.2
Depreciation and amortization expense	0.8	1.0	2.1
Segment net income	$ 6.6	$ 12.6	$ 8.2
Operating Data:			
Propane sales volume (Bbls/d)	21,259	22,604	24,589

(a) Segment gross margin consists of total operating revenues less purchases of propane. Please read How We Evaluate Our Operations above.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues Total operating revenues increased $15.4 million, or 4%, to $375.2 million in 2006 from $359.8 million in 2005, primarily due to the following:

$36.6 million increase attributable to higher propane prices; and

$0.3 million increase related to non-trading derivative activity; offset by

$21.4 million decrease attributable to lower propane sales volumes; and

$0.1 million decrease in transportation revenues.

Purchases of Propane Purchases of propane increased $21.2 million, or 6%, to $359.2 million in 2006 from $338.0 million 2005, primarily due to increased product and transportation costs, and non-cash lower of cost or market inventory adjustments partially offset by a decrease in volume.

Segment Gross Margin Segment gross margin decreased $5.8 million, or 27%, to $16.0 million in 2006 from $21.8 million in 2005, primarily as a result of decreased sales volumes, non-cash lower of cost or market inventory adjustments, and increased product and transportation costs.

Operating and Maintenance Expense Operating and maintenance expense increased $0.4 million, or 5%, to $8.6 million in 2006 from $8.2 million in 2005, primarily as a result of higher labor costs and an increase in lease expenses.

Propane sales decreased 1,345 Bbls/d, or 6%, to 21,259 Bbls/d in 2006 from 22,604 Bbls/d in 2005, due primarily to milder weather in the northeastern United States in 2006.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues Total operating revenues increased $35.3 million, or 11%, to $359.8 million in the 2005 from $324.5 million in 2004, primarily due to the following:

$60.4 million increase attributable to higher propane prices; and

$1.6 million increase related to non-trading derivative activity; offset by

$26.3 million decrease attributable to lower propane sales volumes; and

$0.4 million decrease in transportation revenues.

Purchases of Propane Purchases of propane increased $30.0 million, or 10%, to $338.0 million in 2005 from $308.0 million 2004, primarily due to increased product and transportation costs, partially offset by a decrease in volume.

Segment Gross Margin Segment gross margin increased $5.3 million, or 32%, to $21.8 million in 2005 from $16.5 million in 2004, primarily as a result of increased per unit margins and an increase related to commodity hedging, partially offset by lower sales volumes, and increased product and transportation costs.

Operating and Maintenance Expense Operating and maintenance expense increased $2.0 million, or 32%, to $8.2 million in 2005 from $6.2 million in 2004, primarily due to an increase in lease expenses as a result of the commencement of a new lease arrangement.

Depreciation and Amortization Expense Depreciation and amortization expense decreased $1.1 million, or 52%, to $1.0 million in 2005 from $2.1 million in 2004, primarily as a result of certain assets that became fully depreciated at the beginning of 2005.

Propane sales decreased 1,985 Bbls/d, or 8%, to 22,604 Bbls/d in 2005 from 24,589 Bbls/d in 2004.

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Results of Operations NGL Logistics Segment

This segment includes our NGL transportation pipelines, which includes our Seabreeze and Wilbreeze pipelines, and our interest in Black Lake.

	Year Ended December 31, 2006	2005	2004
	($ in millions except operating data)		
Operating revenues:			
Sales of NGLs	$ 1.1	$ 191.4	$ 156.2
Transportation and processing services	4.2	0.3	
Total operating revenues	5.3	191.7	156.2
Purchases of NGLs	1.2	187.9	152.9
Segment gross margin(a)	4.1	3.8	3.3
Operating and maintenance expense	1.6	0.2	0.2
Earnings from equity method investments(b)	(0.3)	(0.4)	(0.6)
Impairment of equity method investment			4.4
Depreciation and amortization expense	0.9	0.9	0.9
Segment net income	$ 1.9	$ 3.1	$ (1.6)
Operating data:			
NGL pipelines throughput (Bbls/d)(b)	25,040	20,565	20,222

(a) Segment gross margin consists of total operating revenues less purchases of natural gas and NGLs. Please read How We Evaluate Our Operations above.

(b) Includes 45% of the throughput volumes and earnings of Black Lake in 2006 and the period from December 7, 2005 through December 31, 2005. Prior to December 7, 2005, we owned a 50% interest in Black Lake.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues Total operating revenues decreased $186.4 million, or 97%, to $5.3 million in 2006 from $191.7 million in 2005, primarily due to the following:

$190.3 million decrease primarily attributable to lower sales for our Seabreeze pipeline primarily due to a change in contract terms in December 2005, between DCP Midstream, LLC and us, from a purchase and sale arrangement to a fee-based contractual transportation agreement; offset by

$3.9 million increase in transportation revenue attributable to an increase in volumes and a change in contract terms in December 2005, from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Overall, our NGL pipelines experienced an increase in throughput volumes during 2006 as compared to 2005, partially as result of a decrease in September 2005 volumes related to the impact of hurricane Katrina.

Purchases of NGLs Purchases of NGLs decreased $186.7 million, or 99%, to $1.2 million in 2006 from $187.9 million 2005, attributable to lower purchases due to the change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Segment Gross Margin Segment gross margin increased $0.3 million, or 8%, to $4.1 million in 2006 from $3.8 million in 2005, primarily due to increased transportation revenue and higher volumes on our Seabreeze pipeline.

Operating and Maintenance Expense Operating and maintenance expense increased $1.4 million, to $1.6 million in 2006 from $0.2 million in 2005, primarily as a result of higher costs associated with asset integrity, the settlement of a commercial dispute, and equipment rentals.

Earnings from Equity Method Investment Earnings from equity method investment remained relatively constant in 2006 and 2005.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues Total operating revenues increased $35.5 million, or 23%, to $191.7 million in the 2005 from $156.2 million in 2004, primarily due to the following:

$39.7 million increase attributable to higher NGL prices for our Seabreeze pipeline; and

$0.3 million increase in transportation revenue attributable to the change in contract terms in December 2005, from a purchase and redeliver arrangement to a fee-based transport contractual arrangement; offset by

$4.5 million decrease attributable to lower sales volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005, from a purchase and sale arrangement to a fee-based contractual arrangement.

Overall, our Seabreeze pipeline experienced an increase in throughput volumes during 2005 as a result of a temporary disruption in supply from a third party pipeline in March 2004, which was restored in June 2005.

Purchases of NGLs Purchases of NGLs increased $35.0 million, or 23%, to $187.9 million in 2005 from $152.9 million 2004, primarily due to the following:

$39.7 million increase attributable to higher NGL prices for our Seabreeze pipeline; offset by

$4.7 million decrease attributable to the change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Segment Gross Margin Segment gross margin increased $0.5 million, or 15%, to $3.8 million in 2005 from $3.3 million in 2004 mainly as a result of higher volumes on our Seabreeze pipeline.

Earnings from Equity Method Investment Earnings from equity method investment decreased $0.2 million, to $0.4 million in 2005 from $0.6 million in 2004, primarily due to an increase in Black Lake operating costs as a result of pipeline integrity testing during the fourth quarter of 2005.

Impairment of Equity Method Investment In 2004, we recorded an impairment of our equity investment in Black Lake totaling $4.4 million. We did not record an impairment in 2005.

Liquidity and Capital Resources

Prior to our initial public offering in December 2005, our sources of liquidity included cash generated from operations and funding from DCP Midstream, LLC. Our cash receipts were deposited in DCP Midstream, LLC s bank accounts and all cash disbursements were made from these accounts. Prior to our acquisition of our wholesale propane logistics business from DCP Midstream, LLC, its sources of liquidity included cash generated from operations and funding from DCP Midstream, LLC. Cash transactions handled by DCP Midstream, LLC for us, and for our wholesale propane logistics business, were reflected in partners equity as intercompany advances from DCP Midstream, LLC. Following our initial public offering, we maintain our own bank accounts, which are managed by DCP Midstream, LLC.

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from Black Lake;
- borrowings under our revolving credit facility;
- cash realized from the liquidation of securities that are pledged under our term loan facility;
- issuance of additional partnership units; and

- debt offerings.

We anticipate our more significant uses of resources to include:

- capital expenditures
- business acquisitions; and
- quarterly distributions to our unitholders.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions. Our commodity hedging program, as well as any future hedges we enter into, may require us to post collateral depending on commodity price movements. DCP Midstream, LLC has issued parental guarantees for a portion of our commodity hedging instruments that span through 2010 for natural gas swaps and crude oil swaps, which may reduce our requirement to post collateral.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have hedged a significant portion of our anticipated natural gas, NGL and condensate price risk associated with our percentage-of-proceeds arrangements through 2010 with natural gas and crude oil swaps. Additionally, as part of our gathering operations, we recover and sell condensate. We have hedged a significant portion of our anticipated condensate price risk associated with our gathering operations through 2011 with crude oil swaps. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies.

Working Capital Working capital is the amount by which current assets exceed current liabilities. Current assets are reduced by our quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, along with other business factors that affect our net income and cash flows. Our working capital generally increases in periods of rising commodity prices and declines in periods of falling commodity prices. However, our working capital requirements do not necessarily change at the same rate as commodity prices. Our working capital is also impacted by the timing of operating cash receipts and disbursements, payments on debt, capital expenditures, and increases or decreases in restricted investments and other non-current assets.

We had working capital of $33.1 million, $60.1 million and $41.2 million as of December 31, 2006, 2005 and 2004, respectively. The changes in working capital are primarily attributable to the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

Cash Flow Net cash provided by (used in) operating activities, investing activities and financing activities for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
	($ in millions)		

Net cash provided by operating activities	$ 68.9	$ 76.3	$ 24.7
Net cash used in investing activities	$ (82.7)	$ (109.9)	$ (2.6)
Net cash provided by (used in) financing activities	$ 17.8	$ 75.8	$ (22.1)

Net Cash Provided by Operating Activities The changes in net cash provided by operating activities are attributable to our net income adjusted for non-cash charges as presented in the consolidated statements of cash flows and changes in working capital as discussed above.

Net Cash Used in Investing Activities During 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC, for an initial cash outlay of approximately $67.4 million. The historical value of the assets acquired of approximately $56.7 million is reflected in net cash used in investing activities. The remaining $10.7 million is reflected in net cash provided by (used in) financing activities as the excess of the purchase price over the acquired assets. Net cash used in investing activities in 2005 primarily consisted of purchases of available-for-sale securities in the amount of $100.1 million to provide collateral for the term loan portion of our credit facility. Net cash used in investing activities from 2004 through 2006 was also used for capital expenditures, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities.

Net Cash Provided By (Used in) Financing Activities Net cash provided by financing activities in 2006 was primarily comprised of borrowings on our credit facility, which we used to fund the acquisition of our wholesale propane logistics business, partially offset by distributions to our unit holders, repayments of debt, changes in parent advances and the excess purchase price of our wholesale propane logistics business over its historical basis. Net cash provided by financing activities in 2005 was a result of proceeds from the issuance of common units, proceeds from borrowings on our credit facility, partially offset by related distributions to DCP Midstream, LLC. Net cash provided by (used in) financing activities from 2004 through 2005 represents the pass through of our net cash flows to DCP Midstream, LLC under its cash management program as discussed above. We expect to incur future financing cash outflows as a result of distributions to our unitholders and general partners. See Note 12 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

Capital Requirements The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. In our Natural Gas Services segment, 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. In this segment, our expansion capital expenditures may include the construction of new pipelines that would facilitate greater movement of natural gas from western Louisiana and eastern Texas to the market hub that the Pelico system is connected to near Perryville, Louisiana. This hub provides access to several intrastate and interstate pipelines, including pipelines that transport natural gas to the northeastern United States. In our Wholesale Propane Logistics and NGL Logistics segments, our capital expenditures may include the construction of new propane terminals and NGL pipelines that would expand our distribution and transportation capabilities.

Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

- maintenance capital expenditures, which are cash expenditures where we add on to or improve capital assets owned or acquire or construct new capital assets if such expenditures are made to maintain, including over the long term, our operating capacity or revenues; and

- expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets) in each case if such addition, improvement, acquisition or construction is made to increase our operating capacity or revenues or those of our equity interests.

Given our objective of growth through acquisitions, expansion of existing assets and other internal growth projects, we anticipate that we will continue to invest significant amounts of capital to grow and acquire assets. We actively consider a variety of assets for potential acquisitions and expansion projects.

We have budgeted maintenance capital expenditures of $2.5 million and expansion capital expenditures of $7.2 million for the year ending December 31, 2007. During 2006, our capital expenditures totaled $27.2 million, including maintenance capital expenditures of $2.2 million and expansion capital expenditures of $25.0 million. In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC made capital contributions to reimburse us for certain capital projects. We also have an agreement with certain producers whereby these producers will reimburse us for certain capital projects completed by us. As a result, during the year ended December 31, 2006, we had changes in receivables and collections of maintenance capital expenditures, from DCP Midstream, LLC and producers, of approximately $0.4 million. As a result, our total maintenance capital expenditures net of reimbursements were approximately $1.8 million for the year ended December 31, 2006.

Annual maintenance capital expenditures in 2007 are expected to be lower than 2006 as a result of a nonrecurring purchase of equipment in 2006. Annual expansion capital expenditures in 2007 are expected to decrease as a result of the completion of Wilbreeze, an NGL pipeline, in 2006, for which expansion capital expenditures were approximately $11.8 million, partially offset by the cost to complete our new propane terminal. We expect to fund future capital expenditures with restricted investments, funds generated from our operations, borrowings under our credit facility and the issuance of additional partnership units.

Cash Distributions to Unitholders Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all cash and cash equivalents on hand at the end of the quarter, less certain reserves as identified in the partnership agreement, to unitholders of record on the applicable record date. We made cash distributions to our unitholders of $22.1 million during 2006. We intend to make quarterly distribution payments to our unitholders to the extent we have sufficient cash from operations after the establishment of reserves.

Description of Credit Agreement On December 7, 2005, we entered into a 5-year credit agreement, or the Credit Agreement, that consists of:

- a $250.0 million revolving credit facility; and
- a $100.1 million term loan facility.

The revolving credit facility is available for general partnership purposes, including working capital, letters of credit, capital expenditures, acquisitions and cash distributions. We had outstanding debt of $168.0 million under our revolving credit facility as of December 31, 2006. At December 31, 2006, we had $0.2 million of letters of credit outstanding.

We have the option of increasing the size of the revolving credit facility to $550.0 million with the consent of the issuing lenders.

We had outstanding indebtedness of $100.0 million under the term loan facility as of December 31, 2006. Amounts repaid under the term loan facility may not be reborrowed. The full balance on the term loan was collateralized, as required by the Credit Agreement, by investments in high-grade securities as of December 31, 2006 for future use in funding capital expenditures (including potential acquisitions) and in order to reduce our cost of borrowings under the term loan facility.

Our obligations under the revolving credit facility are unsecured, and the term loan facility is secured at all times by high-grade securities in an amount equal to or greater than the outstanding principal amount of the term loan. Any portion of the term loan balance may be repaid at any time, and we may then have access to a corresponding amount of the collateral securities. Upon any prepayment of term loan borrowings, the amount of our revolving credit facility will automatically increase to the extent that the repayment of our term loan facility is made in connection with an acquisition of assets in the midstream energy business.

We may prepay all loans at any time without penalty, subject to the reimbursement of lender breakage costs in the case of prepayment of London Interbank Offered Rate, or LIBOR, borrowings. Indebtedness under the revolving credit facility bears interest, at our option, at either: (1) the higher of Wachovia Bank s prime rate plus an applicable margin of 0% to 0.025% based on leverage level, or the federal funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.27% to 1.025% dependent upon the leverage level or credit rating. As of

December 31, 2006, the revolving credit facility bears interest at the weighted-average rate of 5.86% per annum, and the term loan facility bears interest at a rate of 5.47% per annum. The revolving credit facility incurs an annual facility fee of 0.08% to 0.35% depending on the applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

The Credit Agreement prohibits us from making distributions of Available Cash to unitholders if any default or event of default (as defined in the Credit Agreement) exists. The Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 4.75 to 1.0 and on a temporary basis for not more than three consecutive quarters following the consummation of asset acquisitions in the midstream energy business of not more than 5.25 to 1.0. The Credit Agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Credit Agreement) of equal or greater than 3.0 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Total Contractual Cash Obligations and Off-Balance Sheet Arrangements

A summary of our total contractual cash obligations as of December 31, 2006, is as follows ($ in millions):

	Payments Due by Period				
	Total	**2007**	**2008-2009**	**2010-2011**	**2012 and Thereafter**
Long-term debt(a)	$ 295.8	$ 7.0	$ 13.9	$ 274.9	$
Operating lease obligations	43.1	9.7	13.6	9.4	10.4
Purchase obligations(b)					
Other long-term liabilities(c)	0.5				0.5
Total	$ 339.4	$ 16.7	$ 27.5	$ 284.3	$ 10.9

(a) Includes interest payments on long-term debt which has been hedged because the interest rate is determinable. Interest payments on long-term debt, which has not been hedged, are not included as they are based on floating interest rates and we cannot determine with accuracy the periodic repayment dates or the amounts of the interest payments.

(b) Purchase obligations exclude $117.3 million of accounts payable, $1.1 million of accrued interest payable and $7.4 million of other current liabilities recognized on the December 31, 2006 consolidated balance sheet. Purchase obligations also exclude $0.7 million of current and $2.7 million of long-term unrealized losses on non-trading derivative and hedging instruments included on the December 31, 2006 consolidated balance sheet. These amounts represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities. In addition, many of our gas purchase contracts include short- and long-term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(c) Other long-term liabilities include $0.5 million of asset retirement obligations recognized on the December 31, 2006 consolidated balance sheet.

Our off-balance arrangements consist solely of our operating lease obligations.

Recent Accounting Pronouncements

New Accounting Standards

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FAS 115, or SFAS 159 In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 159 on our consolidated results of operations, cash flows or financial position.

SFAS No. 157, Fair Value Measurements, or SFAS 157 In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard also responds to investors requests for more information about: (1) the extent to which companies measure assets and liabilities at fair value; (2) the information used to measure fair value; and (3) the effect that fair value measurements have on earnings. SFAS 157 will apply whenever another standard requires (or permits) assets or liabilities to be measured at fair value. SFAS 157 does not expand the use of fair value to any new circumstances. SFAS 157 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 157 on our consolidated results of operations, cash flows or financial position.

SFAS No. 154, Accounting Changes and Error Corrections, or SFAS 154 In June 2005, the FASB issued SFAS 154, a replacement of APB Opinion No. 20, or APB 20, *Accounting Changes*, and SFAS No. 3, *Reporting Accounting Changes in Interim Financial Statements.* Among other changes, SFAS 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented under the new accounting principle, unless it is impracticable to do so. SFAS 154 also: (1) provides that a change in depreciation or amortization of a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle; and (2) carries forward without change the guidance within APB 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. The adoption of SFAS 154 on January 1, 2006, did not have a material impact on our consolidated results of operations, cash flows or financial position.

FIN No. 48, Accounting for Uncertainty in Income Taxes *An Interpretation of FASB Statement 109, or FIN 48* In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 are effective for us on January 1, 2007. The adoption of FIN 48 is not expected to have a material impact on our consolidated results of operations, cash flows or financial position.

Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, or EITF 04-13 In September 2005, the FASB ratified the EITF s consensus on Issue 04-13, which requires an entity to treat sales and purchases of inventory between the entity and the same counterparty as one transaction for purposes of applying APB Opinion No. 29, *Accounting for Nonmonetary Transactions,* or APB 29, when such transactions are entered into in contemplation of each other. When such transactions are legally contingent on each other, they are considered to have been entered into in contemplation of each other. The EITF also agreed on other factors that should be considered in determining whether transactions have been entered into in contemplation of each other. EITF 04-13 was applied to new arrangements that we entered into after March 31, 2006. The adoption of EITF 04-13 did not have a material impact on our consolidated results of operations, cash flows or financial position.

Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, or SAB 108 In September 2006, the SEC issued SAB 108 to address diversity in practice in quantifying financial statement misstatements. SAB 108 requires entities to quantify misstatements based on their impact on each of their financial statements and related disclosures. SAB 108 is effective as of the end of our 2006 fiscal year, allowing a one-time transitional cumulative effect adjustment to retained earnings as of January 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The adoption of SAB 108 did not have a material impact on our consolidated results of operations, cash flows or financial position.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

Market risk is the risk of loss arising from adverse change in market prices and rates. We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate the effects of identified risks. In general, we attempt to hedge risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements.

Risk Management Policy

Management has established a comprehensive risk management policy, or the Risk Management Policy, as amended, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices, counterparty credit. Our Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee, which was formed effective February 8, 2006, is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. Prior to the formation of the Risk Management Committee, we were utilizing DCP Midstream, LLC s risk management policies and procedures and risk management committee to monitor and manage market risks.

See Critical Accounting Policies and Estimates Accounting for Risk Management and Hedging Activities and Financial Instruments for further discussion of the accounting for derivative contracts.

Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketing servicers and industrial end-users. Our principal customers in the Wholesale Propane Logistics segment are primarily retail propane distributors. In the NGL Logistics Segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Substantially all of our natural gas, propane and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC s corporate credit policy. DCP Midstream, LLC s corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC s credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Interest Rate Risk

Interest rates on future credit facility draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances. Based on the unhedged borrowings under our revolving credit facility as of December 31, 2006 of $43.0 million, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.2 million annualized increase or decrease in interest expense.

During 2006, we entered into interest rate swap agreements to hedge a portion of the variable rate revolving debt under our Credit Agreement to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. The agreements reprice prospectively approximately every 90 days and expire on December 7, 2010. Under the terms of the interest rate swap agreements, we pay a fixed rate and receive interest payments based on three-month LIBOR on a total notional amount of $125.0 million. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, propane, NGLs and condensate as a result of our gathering, processing, storage and sales activities. We employ established policies and procedures to manage our risks associated with these market fluctuations using various commodity derivatives, including forward contracts, swaps and futures. All derivative activity reflected in the consolidated financial statements for our predecessors was transacted directly by us or DCP Midstream, LLC, and transferred and/or allocated to us, as more fully discussed in Note 1 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. All derivative activity reflected in the consolidated financial statements, which is not related to our predecessors, has been and will be transacted by us.

In 2007 we expect that a $1.00 per MMBtu change in price of natural gas, a $0.10 per gallon change in NGL prices and a $5.00 per barrel change in condensate prices would change our annual gross margin by approximately $0.2 million, $0.4 million and $0.1 million, respectively. These sensitivities include the effect of our executed hedging strategies. Please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies for more information about these hedging strategies. The magnitude of the impact on gross margin of changes in natural gas, NGL and condensate prices presented may not be representative of the magnitude of the impact on gross margin for different commodity prices or contract portfolios. Prices for these products can also affect our profitability indirectly by influencing the level of drilling activity and related opportunities for our services.

Valuation Valuation of a contract s fair value is validated by an internal group independent of the trading group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Hedging Strategies We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas and crude oil contracts to mitigate the effect pricing fluctuations may have on the value of our assets and operations.

We executed a series of derivative financial instruments, which have been designated as cash flow hedges. These financial instruments are intended to hedge the risk of weakening natural gas, NGL and condensate prices. Because of the strong correlation between NGL prices and crude oil prices and the lack of liquidity in the NGL financial market, we have used crude oil swaps to hedge NGL price risk. As a result of these transactions, we have hedged a significant portion of our expected natural gas and NGL commodity price risk through 2010 and condensate commodity price risk through 2011. The margins we earn from condensate sales are directly correlated with crude oil prices. We continually monitor our hedging program and expect to continue to adjust our hedge position as conditions warrant.

The derivative financial instruments we have entered into are typically referred to as swap contracts. These swap contracts entitle us to receive payment from the counterparty to the contract to the extent that the reference price is below the swap price stated in the contract, and we are required to make payment to the counterparty to the extent that the reference price is higher than the swap price stated in the contract. The swap contracts we have entered into to hedge our exposure to price risk associated with natural gas relate to the price of natural gas, settle on a monthly basis and provide that the reference price for each settlement period are the monthly index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area as published by an independent industry publication. The swap contracts we have entered

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into to hedge our exposure to price risk associated with NGLs and condensate relate to the price of crude oil, settle on a monthly basis and provide that the reference price for each settlement period are the average price for the month in which the Asian-pricing of NYMEX futures contracts for light, sweet crude oil. The notional volume for each period covered, and the time periods covered, by these contracts is set forth in the table below.

The counterparties to each of the swap contracts we have entered into are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Based on the forward price curve for NYMEX crude oil contracts, our exposure to a counterparty could exceed a predetermined collateral threshold if the forward curve price exceeds $104.52, $88.60 or $76.33 per barrel of light, sweet crude oil. As the swap contracts settle and the notional volume outstanding decreases, the forward curve price at which point collateral is required would be higher. Predetermined collateral thresholds for hedges guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC s credit rating and would be reduced to $0 in the event DCP Midstream, LLC s credit rating were to fall below investment grade. DCP Midstream, LLC has provided guarantees to support certain natural gas, NGL and condensate hedging contracts through 2010.

The following table sets forth additional information about our natural gas and crude oil swaps used to hedge our natural gas and NGL price risk associated with our percentage-or-proceeds arrangements and our condensate price risk associated with our gathering operations:

Period		**Commodity**	**Notional Volume**	**Reference Price**	**Swap Price**
January 2007	December 2007	Natural Gas	4,100 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2008	December 2008	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2009	December 2009	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2010	December 2010	Natural Gas	3,900 MMBtu/d	Texas Gas Transmission Price(1)	$9.20/MMBtu
January 2007	December 2007	Crude Oil	660 Bbls/d	Asian-pricing of NYMEX crude oil futures(2)	$63.27/Bbl
January 2008	December 2008	Crude Oil	650 Bbls/d	Asian-pricing of NYMEX crude oil futures(2)	$63.27/Bbl
January 2009	December 2009	Crude Oil	650 Bbls/d	Asian-pricing of NYMEX crude oil futures(2)	$63.27/Bbl
January 2010	December 2010	Crude Oil	640 Bbls/d	Asian-pricing of NYMEX crude oil futures(2)	$63.27/Bbl
January 2011	December 2011	Crude Oil	350 Bbls/d	Asian-pricing of NYMEX crude oil futures(2)	$68.50/Bbl

(1) NYMEX index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.

(2) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).

At December 31, 2006, the aggregate fair value of the crude oil and natural gas swaps described above was a $2.5 million net loss and a $9.4 million net gain, respectively.

In addition, we may allow customers to manage their commodity price risk by offering physical deliveries of natural gas at a fixed price. When we enter into commercial arrangements with a fixed price, we also transact an offsetting financial hedge with another party and account for these as fair value hedges. At December 31, 2006, there were no open financial hedges of this nature.

For contracts that are designated and qualify as effective hedge positions of future cash flows, to the extent that the hedge relationships are effective, their market value change impacts are not recognized in current earnings. The unrealized gains or losses on these contracts are deferred in AOCI for cash flow hedges or included in other current or long-term assets or liabilities on the consolidated balance sheets for fair value hedges of firm commitments. Amounts in AOCI are realized in earnings concurrently with the transaction being hedged. However, in instances where the hedging contract no longer qualifies for hedge accounting, amounts included in AOCI through the date of de-designation remain in AOCI until the underlying transaction actually occurs. The derivative contract (if continued as an open position) will be marked to market currently through earnings.

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The fair value of a derivative designated as a fair value hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the results of operations.

The fair value of our qualifying interest rate and commodity hedge positions is expected to be realized in future periods, as detailed in the following table. The amount of cash ultimately realized for these contracts will differ from the amounts shown in the following table due to factors such as market volatility, counterparty default and other unforeseen events that could impact the amount and/or realization of these values.

	Fair Value of Hedge Contracts as of December 31, 2006				
Sources of Fair Value	**Maturity in 2007**	**Maturity in 2008**	**Maturity in 2009**	**Maturity in 2010 and Thereafter**	**Total Fair Value**
			($ in millions)		
Prices supported by quoted market prices and other external sources	$ 0.5	$ (1.0)	$ (0.8)	$ 0.1	$ (1.2)
Prices based on models or other valuation techniques	3.0	1.7	1.9	1.9	8.5
Total	$ 3.5	$ 0.7	$ 1.1	$ 2.0	$ 7.3

The prices supported by quoted market prices and other external sources category includes our interest rate swaps and our Asian-pricing NYMEX crude oil swaps, which have currently quoted monthly crude oil prices for the next 36 months. In addition, this category includes our forward positions in natural gas basis swaps at points for which over-the-counter, or OTC, broker quotes are available. On average, OTC quotes as of December 31, 2006, for natural gas swaps extend one month into the future. These positions are valued against internally developed forward market price curves that are validated and recalibrated against OTC broker quotes. This category also includes strip transactions whose prices are obtained from external sources and then modeled to daily or monthly prices as appropriate.

The prices based on models and other valuation methods category includes the value of transactions for which an internally developed price curve was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

Normal Purchases and Normal Sales If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract s fair value in the consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas, propane or NGLs in future periods.

Asset-Based Activities Our operations of gathering, processing, and transporting natural gas, and the accompanying operations of transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. We occasionally will enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we

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may on occasion use financial derivatives to manage the value of our propane inventories. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings. We manage our asset-based activities in accordance with our Risk Management Policy which limits exposure to market risk and requires regular reporting to management of potential financial exposure. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

Our profitability is affected by changes in prevailing natural gas, propane, NGL and condensate prices. Historically, changes in the prices of most NGL products and condensate have generally correlated with changes in the price of crude oil. Natural gas, propane, NGL and condensate prices are volatile and are impacted by changes in the supply and demand for these commodities, as well as market uncertainty. For a discussion of the volatility of natural gas and NGL prices, please read Risk Factors Risks Related to Our Business. The cash flows from our Natural Gas Services and Wholesale Propane Logistics segments are affected by natural gas, NGL and condensate prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units. Additionally, since weather conditions may adversely affect the overall demand for propane, our wholesale propane business is vulnerable to, and could be adversely affected by, milder winters.

Item 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS

DCP MIDSTREAM PARTNERS, LP CONSOLIDATED FINANCIAL STATEMENTS:

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream Partners GP, LLC
Denver, Colorado:

We have audited the accompanying consolidated balance sheets of DCP Midstream Partners, LP and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, comprehensive income, changes in partners equity, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed in Item 15. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of DCP Midstream Partners, LP and subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule when considered with the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, on December 7, 2005, DCP Midstream Partners, LP was formed and began operating as a separate company. Through December 7, 2005 the accompanying consolidated financial statements have been prepared from the separate records maintained by DCP Midstream, LLC (formerly Duke Energy Field Services, LLC) and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to, DCP Midstream, LLC as a whole.

The consolidated financial statements give retroactive effect to the November 1, 2006 acquisition by DCP Midstream Partners, LP of the wholesale propane logistics business which, as a combination of entities under common control, has been accounted for similar to a pooling of interests as described in Note 1 to the consolidated financial statements. Also as described in Note 1 to the consolidated financial statements, through November 1, 2006, the portion of the accompanying consolidated financial statements attributable to the wholesale propane logistics business, have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the wholesale propane logistics business had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to DCP Midstream, LLC as a whole.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring

Organizations of the Treadway Commission, and our report dated March 14, 2007, expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 14, 2007

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	($ in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 46.2	$ 42.2
Short-term investments	0.6	
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.3 million at both periods	43.4	65.7
Affiliates	34.8	56.5
Inventories	30.1	41.7
Unrealized gains on non-trading derivative and hedging instruments	4.2	0.2
Other	0.3	0.1
Total current assets	159.6	206.4
Restricted investments	102.0	100.4
Property, plant and equipment, net	194.7	178.7
Goodwill	29.3	29.3
Intangible assets, net	2.8	3.2
Equity method investments	5.9	5.5
Unrealized gains on non-trading derivative and hedging instruments	6.5	5.4
Other non-current assets	0.8	1.0
Total assets	$ 501.6	$ 529.9
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 66.9	$ 95.9
Affiliates	50.4	42.4
Unrealized losses on non-trading derivative and hedging instruments	0.7	2.7
Accrued interest payable	1.1	0.8
Other	7.4	4.5
Total current liabilities	126.5	146.3
Long-term debt	268.0	210.1
Unrealized losses on non-trading derivative and hedging instruments	2.7	2.5
Other long-term liabilities	1.0	0.5
Total liabilities	398.2	359.4

Commitments and contingent liabilities		
Partners equity:		
Predecessor equity		69.6
Common unitholders (10,357,143 units issued and outstanding at December 31, 2006 and 2005)	223.4	215.8
Class C unitholders (200,312 units and 0 units issued and outstanding at December 31, 2006 and 2005)	(20.7)	
Subordinated unitholders (7,142,857 convertible units issued and outstanding at December 31, 2006 and 2005)	(101.6)	(109.7)
General partner interest	(5.0)	(5.6)
Accumulated other comprehensive income	7.3	0.4
Total partners equity	103.4	170.5
Total liabilities and partners equity	$ 501.6	$ 529.9

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2006	2005	2004
	($ in millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 535.1	$ 1,004.6	$ 729.8
Sales of natural gas, propane, NGLs and condensate to affiliates	232.8	117.5	85.6
Transportation and processing services	15.0	12.5	9.5
Transportation and processing services to affiliates	12.8	10.6	11.0
Gains (losses) from non-trading derivative activity affiliates	0.1	(0.9)	(1.9)
Total operating revenues	795.8	1,144.3	834.0
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	581.2	889.5	644.2
Purchases of natural gas, propane and NGLs from affiliates	119.2	157.8	116.4
Operating and maintenance expense	23.7	22.4	19.8
Depreciation and amortization expense	12.8	12.7	14.7
General and administrative expense	12.9	5.1	0.9
General and administrative expense affiliates	8.1	9.1	7.8
Total operating costs and expenses	757.9	1,096.6	803.8
Operating income	37.9	47.7	30.2
Interest income	6.3	0.5	
Interest expense	(11.5)	(0.8)	
Earnings from equity method investments	0.3	0.4	0.6
Impairment of equity method investment			(4.4)
Income before income taxes	33.0	47.8	26.4
Income tax expense		3.3	2.5
Net income	$ 33.0	$ 44.5	$ 23.9
Less:			
Net loss (income) attributable to predecessor operations	2.3	(39.8)	(23.9)
General partner interest in net income	(0.7)	(0.1)	
Net income allocable to limited partners	$ 34.6	$ 4.6	$
Net income per limited partner unit basic and diluted	$ 1.90	$ 0.20	$
Weighted-average limited partner units outstanding basic and diluted	17.5	17.5	

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2006	2005	2004
	($ in millions)		
Net income	$ 33.0	$ 44.5	$ 23.9
Other comprehensive income:			
Reclassification of cash flow hedges into earnings	(2.7)		
Net unrealized gains on cash flow hedges	9.6	0.4	
Total other comprehensive income	6.9	0.4	
Total comprehensive income	$ 39.9	$ 44.9	$ 23.9

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS EQUITY

	Predecessor Equity	Common Unitholders	Class C Unitholders	Subordinated Unitholders ($ in millions)	General Partner Interest	Accumulated Other Comprehensive Income	Total Partners Equity
Balance, January 1, 2004	$ 257.6	$	$	$	$	$	$ 257.6
Net change in parent advances	(22.1)						(22.1)
Net income attributable to predecessor operations	23.9						23.9
Balance, December 31, 2004	259.4						259.4
Net change in parent advances	(121.5)						(121.5)
Proceeds from initial public offering of 10,350,000 common units		222.5					222.5
Underwriters discount and offering expenses		(9.3)		(6.4)	(0.4)		(16.1)
Distribution to unitholders	(218.7)						(218.7)
Allocation of predecessor equity in exchange for 7,143 common units, 7,142,857 subordinated units and a 2% general partnership interest (represented by 357,143 equivalent units)	110.6	(0.1)		(105.2)	(5.3)		
Net income attributable to predecessor operations	39.8						39.8
Net income from December 7, 2005 through December 31, 2005		2.7		1.9	0.1		4.7
Other comprehensive income						0.4	0.4
Balance, December 31, 2005	69.6	215.8		(109.7)	(5.6)	0.4	170.5
Net change in parent advances	(10.6)						(10.6)
	(56.7)						(56.7)

Acquisition of wholesale propane logistics business							
Excess purchase price over acquired assets			(26.3)				(26.3)
Issuance of 200,312 Class C units			5.6				5.6
Proceeds from general partner interest (represented by 4,088 equivalent units)					0.1		0.1
Contributions by unitholders				2.8	0.2		3.0
Distributions to unitholders		(12.8)	(0.1)	(8.8)	(0.4)		(22.1)
Net loss attributable to predecessor operations	(2.3)						(2.3)
Net income		20.4	0.1	14.1	0.7		35.3
Other comprehensive income						6.9	6.9
Balance, December 31, 2006	$	$ 223.4	(20.7)	$ (101.6)	$ (5.0)	$ 7.3	$ 103.4

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	2005 ($ in millions)	2004
OPERATING ACTIVITIES:			
Net income	$ 33.0	$ 44.5	$ 23.9
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense and impairment charge	12.8	12.7	19.1
Undistributed earnings from equity method investments	(0.3)	(0.4)	(0.6)
Deferred income tax benefit		(0.5)	(0.1)
Other, net	(2.4)	0.1	(0.2)
Change in operating assets and liabilities which provided (used) cash:			
Accounts receivable	43.1	(30.7)	(19.0)
Inventories	11.6	(21.0)	0.2
Net unrealized (gains) losses on non-trading derivative and hedging instruments	(0.1)	0.1	0.3
Accounts payable	(31.5)	74.7	0.8
Accrued interest	0.3	0.8	
Income tax payable		(3.2)	(0.1)
Other current assets and liabilities	2.0	(0.7)	0.4
Other non-current assets and liabilities	0.4	(0.1)	
Net cash provided by operating activities	68.9	76.3	24.7
INVESTING ACTIVITIES:			
Capital expenditures	(27.2)	(10.8)	(3.3)
Acquisition of wholesale propane logistics business	(56.7)		
Proceeds from sales of assets	0.3	1.2	0.7
Purchases of available-for-sale securities	(7,372.4)	(731.0)	
Proceeds from sales of available-for-sale securities	7,373.3	630.8	
Other investing activities		(0.1)	
Net cash used in investing activities	(82.7)	(109.9)	(2.6)
FINANCING ACTIVITIES:			
Borrowings under debt facilities	78.0	210.1	
Repayments of debt	(20.1)		
Deferred financing costs	(0.2)	(0.5)	
Proceeds from issuance of common units, net of offering costs		206.4	
Proceeds from issuance of equivalent units to general partner	0.1		
Excess purchase price over acquired assets	(10.7)		
Net change in advances from DCP Midstream, LLC	(10.6)	(121.5)	(22.1)

Distributions to unitholders		(22.1)		(218.7)		
Contributions from unitholders		3.4				
Net cash provided by (used in) financing activities		17.8		75.8		(22.1)
Net change in cash and cash equivalents		4.0		42.2		
Cash and cash equivalents, beginning of period		42.2				
Cash and cash equivalents, end of period	$	46.2	$	42.2	$	
Supplementary disclosure of cash flow information:						
Cash paid for interest expense, net of capitalized interest	$	11.1	$		$	
Cash paid for income taxes	$		$	2.6	$	2.7

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years Ended December 31, 2006, 2005 and 2004

1. Description of Business and Basis of Presentation

DCP Midstream Partners, LP, with its consolidated subsidiaries, or us, we or our, is engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas and the business of producing, transporting and selling propane and natural gas liquids, or NGLs.

Our partnership includes: our North Louisiana system assets, or Minden, Ada, and Pelico; our Seabreeze NGL transportation pipeline; our 45% equity method investment in Black Lake Pipe Line Company, or Black Lake, that were contributed to us on December 7, 2005 by DCP Midstream, LLC (formerly Duke Energy Field Services, LLC); our Wilbreeze NGL transportation pipeline which was completed in December 2006; and our wholesale propane logistics business that was acquired by us on November 1, 2006 from DCP Midstream, LLC. DCP Midstream, LLC is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. Prior to December 7, 2005, DCP Midstream Partners Predecessor (defined below) owned a 50% equity interest in Black Lake. DCP Midstream, LLC owns a 5% interest in Black Lake, effective with the date of our initial public offering, and an affiliate of BP PLC owns the remaining interest and is the operator of Black Lake. Spectra Energy is the natural gas business that was spun off from Duke Energy Corporation, or Duke Energy, effective January 2, 2007.

In November 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC for approximately $82.9 million, comprised of $77.3 million in cash ($9.9 million of which was paid in January 2007) and $5.6 million in limited partner units. Included in the acquisition was $10.5 million of costs incurred by DCP Midstream, LLC for the construction of a new propane pipeline terminal. In conjunction with the issuance of limited partner units, the general partner maintained its 2% ownership level, in exchange for $0.1 million. See Note 4 for additional information.

Net assets contributed by DCP Midstream, LLC represent a transfer of net assets between entities under common control. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC s basis in the net assets contributed. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method. The amount of the purchase price in excess of DCP Midstream, LLC s basis in the net assets, if any, is recognized as a reduction to partners equity.

We closed our initial public offering of 10,350,000 common units at a price of $21.50 per unit on December 7, 2005. Proceeds from the initial public offering were $206.4 million, net of offering costs. In addition, concurrent with the initial public offering, DCP Midstream, LLC contributed to us the assets described above and retained: (1) a 2% general partner interest in our partnership; (2) 7,142,857 subordinated units; and (3) 7,143 common units. Following the equity transactions related to the acquisition of our wholesale propane logistics business noted above, DCP Midstream, LLC owns in aggregate an approximate 43% interest in our partnership. See Note 12 for information related to the distribution rights of the common, Class C and subordinated unitholders and the incentive distribution rights held by the general partner.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, which is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC and its affiliates employees provide administrative support to us and operate our assets.

The consolidated financial statements include our accounts, and prior to December 7, 2005 the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries, which we refer to as DCP Midstream Partners Predecessor, upon the closing of our initial public offering. In November 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC in a

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

transaction among entities under common control. Accordingly, our financial information includes the historical results of our wholesale propane logistics business for all periods presented.

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. We refer to DCP Midstream Partners Predecessor, and the assets, liabilities and operations of our wholesale propane logistics business prior to our acquisition from DCP Midstream, LLC in November 2006, collectively as our predecessors. The consolidated financial statements of our predecessors have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessors had been operated as an unaffiliated entity. All significant intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations have been identified in the consolidated financial statements as transactions between affiliates (see Note 5).

2. Summary of Significant Accounting Policies

Use of Estimates Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results could differ from those estimates.

Reclassifications Certain prior period amounts have been reclassified in the consolidated financial statements to conform to the current period presentation.

Cash and Cash Equivalents We consider investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less to be cash equivalents.

Short-Term and Restricted Investments Short-term investments consist of $0.6 million at December 31, 2006. We had no short-term investments at December 31, 2005. We invest available cash balances in various financial instruments, such as tax-exempt debt securities, that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features, which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted.

Restricted investments consist of $102.0 million and $100.4 million in investments in commercial paper and various other high-grade debt securities at December 31, 2006 and 2005, respectively. These investments are used as collateral to secure the term loan portion of our credit facility and are to be used only for future capital expenditures.

We have classified all short-term and restricted investments as available-for-sale under Statement of Financial Accounting Standards, or SFAS, No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, as we do not intend to hold them to maturity, nor are they bought or sold with the objective of generating profit on short-term differences in prices. These investments are recorded at fair value, with changes in fair value recorded as unrealized gains and losses in accumulated other comprehensive income, or AOCI. No gains or losses were deferred in AOCI at December 31, 2006 or 2005. The cost, including accrued interest on investments, approximates fair value, due to the short-term, highly liquid nature of the securities held by us, and as interest rates are re-set on a daily, weekly or monthly basis.

Gas and NGL Imbalance Accounting Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using current market prices or the weighted-average prices of natural gas

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash.

Included in the consolidated balance sheets as accounts receivable trade, were imbalances of $0.1 million and $1.1 million at December 31, 2006 and 2005, respectively. Included in the consolidated balance sheets as accounts payable trade, were imbalances of $0.9 million and $2.5 million at December 31, 2006 and 2005, respectively.

Inventories Inventories consist primarily of propane. Inventories are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory on the consolidated balance sheets.

Property, Plant and Equipment Property, plant and equipment are recorded at historical cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets (see Note 6). The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. We recognize a liability of a conditional asset retirement obligation as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Goodwill and Intangible Assets Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. The goodwill on the consolidated balance sheets was recognized by DCP Midstream, LLC when it acquired certain assets which are now included in the wholesale propane logistics business, and was allocated based on fair value to the wholesale propane logistics business in order to present historical information about the assets we acquired. We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess.

Intangible assets consist primarily of commodity contracts. The commodity contracts are amortized on a straight-line basis over the period of expected future benefit, ranging from approximately five to 25 years (see Note 7).

Investment in and Impairment of Equity Method Investments We account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, under the equity method.

We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. If the estimated fair value is less than the carrying value and we consider the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment.

Impairment of Long-Lived Assets We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse change in legal factors or business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset s carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management s intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Unamortized Debt Expense Expenses incurred with the issuance of long-term debt are amortized over the terms of the debt using the effective interest method. These expenses are recorded on the consolidated balance sheet as other non-current assets.

Accounting for Risk Management and Hedging Activities and Financial Instruments Each derivative not qualifying for the normal purchases and normal sales exception under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, or SFAS 133, is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging instruments at fair value until the contractual settlement period impacts earnings.

All derivative activity reflected in the consolidated financial statements for our predecessors was transacted by us or by DCP Midstream, LLC and its subsidiaries, and transferred and/or allocated to us. All derivative activity reflected in the consolidated financial statements, which is not related to our predecessors, has been and will be transacted by us, although DCP Midstream, LLC personnel execute various transactions on our behalf (see Note 5). We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activities, are designated as non-trading derivative activity. For the periods presented, we did not have any trading derivative activity, however, we do have cash flow and fair value hedge activity, normal purchases and normal sales activity, and non-trading derivative activity included in the consolidated financial statements. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Non-Trading Derivative Activity	Mark-to-market method(a)	Net basis in gains (losses) from non-trading derivative activity
Cash Flow Hedge	Hedge method(b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method(b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method(c)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale

(a) Mark-to-market An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in gains (losses) from non-trading derivative activity during the current period.

(b) Hedge method An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery period impacts earnings. For fair value hedges, the change in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.

(c) Accrual method An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery period impacts earnings.

Cash Flow and Fair Value Hedges For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge in accordance with SFAS 133. In addition, we formally assess, both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in partners equity as AOCI, and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the results of operations.

Valuation When available, quoted market prices or prices obtained through external sources are used to determine a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Revenue Recognition We generate the majority of our revenues from: (1) sales of natural gas, propane, NGLs and condensate; (2) natural gas gathering, processing and transportation, from which we generate revenue primarily through the compression, gathering, treating, processing and transportation of natural gas; (3) NGL transportation from which we generate revenues from transportation fees; as well as (4) trading and marketing of natural gas and NGLs.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following arrangements:

> *Fee-based arrangements* Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing or transporting natural gas; and transporting NGLs. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues from these arrangements would be reduced.
>
> *Percentage-of-proceeds arrangements* Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, transport the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs at index prices based

on published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Under these types of arrangements, our revenues correlate directly with the price of natural gas and NGLs.

Propane sales arrangements Under propane sales arrangements, we generally purchase propane from natural gas processing plants and fractionation facilities, and crude oil refineries. We sell propane on a

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

wholesale basis to retail propane distributors, who in turn resell to their retail customers. Our sales of propane are not contingent upon the resale of propane by propane distributors to their retail customers.

Our marketing of natural gas and NGLs consists of physical purchases and sales, as well as positions in derivative instruments.

We recognize revenues for sales and services under the four revenue recognition criteria, as follows:

Persuasive evidence of an arrangement exists Our customary practice is to enter into a written contract, executed by both us and the customer.

Delivery Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.

The fee is fixed or determinable We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.

Collectability is probable Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers financial position (for example, cash position and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is recognized when the fee is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody to the product, and incur the risks and rewards of ownership. Effective April 1, 2006, any new or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for non-trading derivative activity net in the consolidated statements of operations as gains (losses) from non-trading derivative activity. These activities include mark-to-market gains and losses on energy trading contracts and the financial or physical settlement of energy trading contracts.

Significant Customer We had one customer, a third party, that accounted for 17% and 18% of total operating revenues for the years ended December 31, 2005 and 2004, respectively. Revenues from this customer are reported in the NGL Logistics Segment. There were no customers that accounted for more than 10% of total operating revenues for the year ended December 31, 2006. We also had significant transactions with affiliates (see Note 5), and with suppliers of propane (see Item 1. Business Wholesale Propane Logistics Segment.)

Environmental Expenditures Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not generate current or future revenue are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Environmental liabilities as of December 31, 2006 and 2005, included in the consolidated balance sheets as other current liabilities, were not significant.

Equity-Based Compensation Under the DCP Midstream Partners, LP Long-Term Incentive Plan, or the LTIP, equity instruments may be granted to our key employees. The General Partner adopted the LTIP for employees, consultants and directors of the General Partner and its affiliates who perform services for us. The LTIP provides for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of distribution equivalent rights, or DERs. Subject to

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adjustment for certain events, an aggregate of 850,000 common units may be delivered pursuant to awards under the LTIP. Awards that are cancelled, forfeited or are withheld to satisfy the General Partner s tax withholding obligations are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the General Partner s board of directors. Awards were first granted under the LTIP during 2006.

Effective January 1, 2006, we adopted the provisions of SFAS No. 123 (Revised 2004), *Share-Based Payment*, or SFAS 123R, which establishes accounting for stock-based awards exchanged for employee and non-employee services. Accordingly, equity classified stock-based compensation cost is measured at grant date, based on the estimated fair value of the award, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date and is recognized over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees are accounted for under the provisions of EITF No. 96-18, *Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services.*

Income Taxes We are structured as a master limited partnership which is a pass-through entity for federal income tax purposes. Our wholesale propane logistics business changed its tax structure, effective December 7, 2005, such that it became a pass-through entity. Prior to December 7, 2005, our wholesale propane logistics business was considered taxable for United States income tax purposes. Our wholesale propane logistics business followed the asset and liability method of accounting for income taxes, whereby deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Subsequent to December 7, 2005, our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is includable in the federal returns of each partner.

Comprehensive Income Comprehensive income consists of net income and other comprehensive income, which includes unrealized gains and losses on the effective portion of derivative instruments classified as cash flow hedges.

Net Income per Limited Partner Unit Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income, less pro forma general partner incentive distributions under EITF Issue No. 03-6, *Participating Securities and the Two Class Method Under FASB Statement No. 128*, or EITF 03-6, by the weighted-average number of outstanding limited partner units during the period (see Note 16).

3. New Accounting Standards

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FAS 115, or SFAS 159 In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 159 on our consolidated results of operations, cash flows or financial position.

SFAS No. 157, Fair Value Measurements, or SFAS 157 In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard also responds to investors requests for more information about: (1) the extent to which companies measure assets

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and liabilities at fair value; (2) the information used to measure fair value; and (3) the effect that fair value measurements have on earnings. SFAS 157 will apply whenever another standard requires (or permits) assets or liabilities to be measured at fair value. SFAS 157 does not expand the use of fair value to any new circumstances. SFAS 157 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 157 on our consolidated results of operations, cash flows or financial position.

SFAS No. 154, Accounting Changes and Error Corrections, or SFAS 154 In June 2005, the FASB issued SFAS 154, a replacement of APB Opinion No. 20, or APB 20, *Accounting Changes*, and SFAS No. 3, *Reporting Accounting Changes in Interim Financial Statements.* Among other changes, SFAS 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented under the new accounting principle, unless it is impracticable to do so. SFAS 154 also: (1) provides that a change in depreciation or amortization of a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle; and (2) carries forward without change the guidance within APB 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. The adoption of SFAS 154 on January 1, 2006, did not have a material impact on our consolidated results of operations, cash flows or financial position.

FIN No. 48, Accounting for Uncertainty in Income Taxes *An Interpretation of FASB Statement 109, or FIN 48* In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 are effective for us on January 1, 2007. The adoption of FIN 48 is not expected to have a material impact on our consolidated results of operations, cash flows or financial position.

EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, or EITF 04-13 In September 2005, the FASB ratified the EITF s consensus on Issue 04-13, which requires an entity to treat sales and purchases of inventory between the entity and the same counterparty as one transaction for purposes of applying APB Opinion No. 29, *Accounting for Nonmonetary Transactions*, or APB 29, when such transactions are entered into in contemplation of each other. When such transactions are legally contingent on each other, they are considered to have been entered into in contemplation of each other. The EITF also agreed on other factors that should be considered in determining whether transactions have been entered into in contemplation of each other. EITF 04-13 was applied to new arrangements that we entered into after March 31, 2006. The adoption of EITF 04-13 did not have a material impact on our consolidated results of operations, cash flows or financial position.

Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, or SAB 108 In September 2006, the Securities and Exchange Commission, or SEC, issued SAB 108 to address diversity in practice in quantifying financial statement misstatements. SAB 108 requires entities to quantify misstatements based on their impact on each of their financial statements and related disclosures. SAB 108 is effective as of the end of our 2006 fiscal year, allowing a one-time transitional cumulative effect adjustment to retained earnings as of January 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The adoption of SAB 108 did not have a material impact on our consolidated results of operations, cash flows or financial position.

4. Acquisition

On November 1, 2006, we acquired our wholesale propane logistics business, from DCP Midstream, LLC for aggregate consideration consisting of approximately $82.9 million, which consisted of $77.3 million in

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cash ($9.9 million of which was paid in January 2007), and the issuance of 200,312 Class C units valued at approximately $5.6 million. Included in the aggregate consideration was $10.5 million of costs associated with the construction of a new propane pipeline terminal.

The transfer of assets between DCP Midstream, LLC and us represents a transfer of assets between entities under common control. Transfers of net assets or exchanges of shares between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method. The $26.3 million excess purchase price over the historical basis of the net acquired assets is recorded as a reduction to partners equity for financial accounting purposes.

The following table presents the impact on our condensed consolidated financial position at December 31, 2005, adjusted for the acquisition of our wholesale propane logistics business from DCP Midstream, LLC ($ in millions):

	DCP Midstream Partners, LP	Wholesale Propane Logistics Business	Combined DCP Midstream Partners, LP
ASSETS			
Current assets:			
Cash and cash equivalents	$ 42.2	$	$ 42.2
Accounts receivable	82.0	40.2	122.2
Inventories	0.1	41.6	41.7
Other	0.2	0.1	0.3
Total current assets	124.5	81.9	206.4
Restricted investments	100.4		100.4
Property, plant and equipment, net	168.9	9.8	178.7
Goodwill and intangible assets, net	2.1	30.4	32.5
Other non-current assets	11.4	0.5	11.9
Total assets	$ 407.3	$ 122.6	$ 529.9
LIABILITIES AND PARTNERS EQUITY			
Accounts payable and other current liabilities	$ 93.4	$ 52.9	$ 146.3
Long-term debt	210.1		210.1
Other long-term liabilities	2.9	0.1	3.0
Total liabilities	306.4	53.0	359.4
Commitments and contingent liabilities			
Partners equity:			

Net equity		100.5		69.6		170.1
Accumulated other comprehensive income		0.4				0.4
Total partners equity		100.9		69.6		170.5
Total liabilities and partners equity	$	407.3	$	122.6	$	529.9

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables present the impact on the condensed consolidated statements of operations, adjusted for the acquisition of our wholesale propane logistics business from DCP Midstream, LLC, for the periods presented ($ in millions):

	Year Ended December 31, 2005		
	DCP Midstream Partners, LP and Predecessor	Wholesale Propane Logistics Business	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 762.3	$ 359.8	$ 1,122.1
Transportation and other	22.2		22.2
Total operating revenues	784.5	359.8	1,144.3
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	709.3	338.0	1,047.3
Operating and maintenance expense	14.2	8.2	22.4
Depreciation and amortization expense	11.7	1.0	12.7
General and administrative expense	11.4	2.8	14.2
Total operating costs and expenses	746.6	350.0	1,096.6
Operating income	37.9	9.8	47.7
Interest expense, net	(0.3)		(0.3)
Earnings from equity method investments	0.4		0.4
Income tax expense		(3.3)	(3.3)
Net income	$ 38.0	$ 6.5	$ 44.5

	Year Ended December 31, 2004		
	DCP Midstream Partners Predecessor	Wholesale Propane Logistics Business	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 489.7	$ 325.7	$ 815.4
Transportation and other	19.8	(1.2)	18.6

Total operating revenues		509.5		324.5		834.0
Operating costs and expenses:						
Purchases of natural gas, propane and NGLs		452.6		308.0		760.6
Operating and maintenance expense		13.6		6.2		19.8
Depreciation and amortization expense		12.6		2.1		14.7
General and administrative expense		6.5		2.2		8.7
Total operating costs and expenses		485.3		318.5		803.8
Operating income		24.2		6.0		30.2
Earnings from equity method investments		0.6				0.6
Impairment of equity method investment		(4.4)				(4.4)
Income tax expense				(2.5)		(2.5)
Net income	$	20.4	$	3.5	$	23.9

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

DCP Midstream, LLC provided centralized corporate functions on behalf of our predecessor operations, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The predecessor s share of those costs was allocated based on the predecessor s proportionate net investment (consisting of property, plant and equipment, net, equity method investment, and intangible assets, net) as compared to DCP Midstream, LLC s net investment. In management s estimation, the allocation methodologies used were reasonable and resulted in an allocation to the predecessors of their respective costs of doing business, which were borne by DCP Midstream, LLC.

Omnibus Agreement

We have entered into an omnibus agreement, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, as amended, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee of $4.8 million related to the DCP Midstream Predecessor business contributed to us upon our initial public offering. The annual fee is for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. In the second quarter of 2006, we amended the Omnibus Agreement. The amendment clarifies that the annual fee of $4.8 million under the agreement is fixed at such amount, subject to annual increases in the Consumer Price Index, and increases in connection with the expansion of our operations through the acquisition or construction of new assets or businesses. The Omnibus Agreement was further amended in November 2006, in conjunction with the acquisition of our wholesale propane logistics business from DCP Midstream, LLC. Under this amendment, we pay DCP Midstream, LLC an additional annual fee of $2.0 million related to our wholesale propane logistics business, subject to the same conditions noted above. This additional $2.0 million fee was prorated in 2006 from the date of our wholesale propane logistics business acquisition.

The Omnibus Agreement addresses the following matters:

- our obligation to reimburse DCP Midstream, LLC for the payment of operating expenses, including salary and benefits of operating personnel, it incurs on our behalf in connection with our business and operations;

- our obligation to reimburse DCP Midstream, LLC for providing us with general and administrative services with respect to our business and operations, which is $6.8 million, subject to an increase for 2007 and 2008 based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of our special committee;

- our obligation to reimburse DCP Midstream, LLC for insurance coverage expenses it incurs with respect to our business and operations and with respect to director and officer liability coverage;

DCP Midstream, LLC s obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities;

DCP Midstream, LLC s obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements were in

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effect as of the closing of our initial public offering until the earlier to occur of the fifth anniversary of the closing of our initial public offering or such time as we obtain an investment grade credit rating from either Moody s Investor Services, Inc. or Standard & Poor s Ratings Group with respect to any of our unsecured indebtedness; and

DCP Midstream, LLC s obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts.

Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions, will be terminable by DCP Midstream, LLC at its option if the general partner is removed without cause and units held by the 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, the general partner (DCP Midstream GP, LP) or the General Partner (DCP Midstream GP, LLC).

Competition

None of DCP Midstream, LLC, nor any of its affiliates, including Spectra Energy and ConocoPhillips, is restricted, under either the partnership agreement or the Omnibus Agreement, from competing with us. DCP Midstream, LLC and any of its affiliates, including Spectra Energy and ConocoPhillips, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the Omnibus Agreement, DCP Midstream, LLC will indemnify us for three years after the closing of our initial public offering against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing date of our initial public offering. DCP Midstream, LLC s maximum liability for this indemnification obligation does not exceed $15 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DCP Midstream, LLC has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

Additionally, DCP Midstream, LLC will indemnify us for losses attributable to title defects, retained assets and liabilities (including preclosing litigation relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DCP Midstream, LLC for all losses attributable to the postclosing operations of the assets contributed to us, to the extent not subject to DCP Midstream, LLC s indemnification obligations. In addition, DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from 2005 through 2007. DCP Midstream, LLC has also agreed to indemnify us for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of pipeline integrity testing that occurred in 2006. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Any reimbursements of these expenses from DCP Midstream, LLC will be recognized by us as a capital contribution. Reimbursements related to the Seabreeze pipeline integrity repairs in 2006 were not significant.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Agreements and Transactions with DCP Midstream, LLC

Prior to our initial public offering on December 7, 2005, we participated in DCP Midstream, LLC s cash management program. As a result, we had no cash balances on our consolidated balance sheets and all cash management activity was performed by DCP Midstream, LLC on our behalf, including collection of receivables, payment of payables, and the settlement of sales and purchases transactions between us and DCP Midstream, LLC, which were recorded as parent advances and included in accounts receivable affiliates or accounts payable affiliates. Subsequent to the initial public offering, we maintain separate cash accounts, which are managed by DCP Midstream, LLC.

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system that are periodically used for the benefit of Pelico. DCP Midstream, LLC is able to source natural gas upstream of Pelico and deliver it to the inlet of the Pelico system, and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. Because of DCP Midstream, LLC s ability to move natural gas around Pelico, there are certain contractual relationships around Pelico that define how natural gas is bought and sold between us and DCP Midstream, LLC.

Effective December 2005, we entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will purchase natural gas and transport it to the Pelico system, where we will buy the gas from DCP Midstream, LLC at its weighted-average cost delivered to the Pelico system, plus a contractually agreed-to marketing fee and other related adjustments. In addition, for a significant portion of the gas that we sell out of our Pelico system, DCP Midstream, LLC will purchase that natural gas from us and transport it to a sales point at a price equal to its net weighted-average sales price, less a contractually agreed-to marketing fee and other related adjustments. We generally report revenues and purchases associated with these activities gross in the consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates and purchases of natural gas, propane and NGLs from affiliates.

The above agreement was amended and restated effective February 2006 in response to DCP Midstream, LLC securing additional access to natural gas for our Pelico system. The revised agreement is described below:

DCP Midstream, LLC will supply Pelico s system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. We generally report purchases associated with these activities gross in the consolidated statements of operations as purchases of natural gas, propane and NGLs from affiliates.

If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index-based price, less a contractually agreed-to marketing fee. We generally report revenues associated with these activities gross in the consolidated statements of operations as sales of natural gas, propane and NGLs to affiliates.

In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC, plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential, plus a fixed fuel charge and other related adjustments. We generally report revenues and purchases associated with these activities net in the consolidated statements of operations as transportation and processing services to affiliates.

Effective December 2005, we entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that for certain industrial end-user customers of the Pelico system we may sell

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

aggregated natural gas to a subsidiary of DCP Midstream, LLC, which in turn would resell natural gas to these customers. The sales price to the subsidiary of DCP Midstream, LLC is equal to that subsidiary of DCP Midstream, LLC s net weighted-average sales price delivered from the Pelico system less a contractually agreed-to marketing fee, which is recorded in the consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates.

Effective December 2005, we entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will purchase the NGLs that were historically purchased by the Seabreeze pipeline, and DCP Midstream, LLC will pay us to transport the NGLs pursuant to a fee-based rate that will be applied to the volumes transported. We have entered into this fee-based contractual arrangement with the objective of generating approximately the same operating income per barrel transported that we realized when we were the purchaser and seller of NGLs. We do not take custody to the products transported on the NGL pipeline; rather, the shipper retains custody and the associated commodity price risk. DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a 17-year transportation agreement expiring in 2022. We generally report revenues associated with these activities in the consolidated statements of operations as transportation and processing services to affiliates.

In December 2006, we completed construction of our Wilbreeze pipeline, which connects a DCP Midstream, LLC gas processing plant to our Seabreeze pipeline. The project is supported by a 10-year NGL product dedication agreement with DCP Midstream, LLC.

We sell NGLs and condensate from our Minden and Ada processing plants, and condensate from our Pelico system to a subsidiary of DCP Midstream, LLC equal to that subsidiary of DCP Midstream, LLC s net weighted-average sales price adjusted for transportation and other charges from the tailgate of the respective asset, which is recorded in the consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates. We also sell propane to a subsidiary of DCP Midstream, LLC.

We anticipate continuing to purchase these commodities from and sell these commodities to DCP Midstream, LLC in the ordinary course of business.

In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for capital projects, which were forecasted to be completed prior to our initial public offering, but were not completed by that date. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $3.4 million during 2006, to reimburse us for the capital costs we incurred, primarily for growth capital projects. At December 31, 2006, all of these projects were completed.

We had an operating lease with an affiliate during the years ended December 31, 2005 and 2004. Operating lease expense related to this lease was $0.7 million and $2.8 million for the years ended December 31, 2005 and 2004, respectively.

DCP Midstream, LLC was a significant customer during the years ended December 31, 2006, 2005 and 2004.

Duke Energy and Spectra Energy

Prior to December 31, 2006, we charged transportation fees, sold portion of our residue gas to, and purchased raw natural gas from, Duke Energy and its affiliates. We anticipate continuing to purchase and sell these commodities to

Spectra Energy and its affiliates in the ordinary course of business.

ConocoPhillips

We have multiple agreements whereby we provide a variety of services to ConocoPhillips and its affiliates. The agreements include fee-based and percentage-of-proceeds gathering and processing

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

arrangements, gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received \$3.9 million, \$0.2 million and \$0.3 million of capital reimbursements during the years ended December 31, 2006, 2005 and 2004, respectively.

The following table summarizes the transactions with DCP Midstream, LLC, Duke Energy and ConocoPhillips as described above (\$ in millions):

	Year Ended December 31,		
	2006	2005	2004
DCP Midstream, LLC:			
Sales of natural gas, propane, NGLs and condensate	$ 231.7	$ 108.8	$ 71.6
Transportation and processing services	$ 4.8	$ 0.3	$ 0.6
Purchases of natural gas, propane and NGLs	$ 102.9	$ 134.4	$ 94.4
Gains (losses) from non-trading derivative activity	$ 0.1	$ (0.9)	$ (1.9)
General and administrative expense	$ 8.1	$ 9.1	$ 7.8
Duke Energy:			
Sales of natural gas, propane, NGLs and condensate	$	$ 1.4	$ 10.3
Transportation and processing services	$	$ 0.3	$ 0.5
Purchases of natural gas, propane and NGLs	$ 3.4	$ 4.7	$ 3.4
ConocoPhillips:			
Sales of natural gas, propane, NGLs and condensate	$ 1.1	$ 7.3	$ 3.7
Transportation and processing services	$ 8.0	$ 10.0	$ 9.9
Purchases of natural gas, propane and NGLs	$ 12.9	$ 18.7	$ 18.6

We had accounts receivable and accounts payable with affiliates as follows (\$ in millions):

	December 31,	
	2006	2005
DCP Midstream, LLC:		
Accounts receivable	$ 30.0	$ 53.5
Accounts payable	$ 46.6	$ 15.9
Duke Energy:		
Accounts receivable	$ 0.2	$ 0.4
Accounts payable	$ 1.8	$ 24.0
ConocoPhillips:		
Accounts receivable	$ 4.6	$ 2.6
Accounts payable	$ 2.0	$ 2.5

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows ($ in millions):

	Depreciable Life	December 31, 2006	2005
Gathering systems	15 30 Years	$ 107.3	$ 95.9
Processing plants	25 30 Years	53.2	53.4
Terminals	25 30 Years	8.2	8.2
Transportation	25 30 Years	139.6	127.4
General plant	3 5 Years	3.6	3.6
Construction work in progress		16.2	11.4
Property, plant and equipment		328.1	299.9
Accumulated depreciation		(133.4)	(121.2)
Property, plant and equipment, net		$ 194.7	$ 178.7

Depreciation expense was $12.4 million, $12.0 million and $13.1 million for the years ended December 31, 2006, 2005 and 2004, respectively.

In addition, property, plant and equipment includes $1.4 million, $1.1 million and $0.1 million of non-cash additions for the years ended December 31, 2006, 2005 and 2004, respectively.

Asset Retirement Obligations Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The asset retirement obligation, included in other long-term liabilities in the consolidated balance sheets, was $0.5 million and $0.3 million at December 31, 2006 and 2005, respectively. Accretion expense for the years ended December 31, 2006, 2005 and 2004 was not significant.

7. Goodwill and Intangible Assets

Goodwill consists of the amount that was recognized by DCP Midstream, LLC when it acquired certain assets which are now included in our Wholesale Propane Logistics segment, and was allocated based on fair value to the wholesale propane logistics business in order to present historical information about the assets we acquired in November 2006. As this was a transaction among entities under common control, our financial information includes the results of our wholesale propane logistics business for all periods presented. There were no changes in the $29.3 million carrying amount of goodwill during the years ended December 31, 2006 or 2005. We perform an annual goodwill impairment test, and update the test during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We use a discounted cash flow analysis supported by market valuation multiples to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. Our annual goodwill impairment test indicated that our reporting unit s fair value exceeded its carrying or book value; therefore, we have determined that there is no indication of impairment.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Intangible assets consist primarily of commodity purchase contracts. The gross carrying amount and accumulated amortization for the commodity purchase contracts and other intangible assets are included in the accompanying consolidated balance sheets as intangible assets, and are as follows ($ in millions):

	December 31, 2006	December 31, 2005
Gross carrying amount	$ 4.4	$ 11.0
Accumulated amortization	(1.6)	(7.8)
Intangible assets, net	$ 2.8	$ 3.2

One customer has notified us that they intend to exercise their early termination right prior to the end of the contract term. Accordingly, we are not amortizing the estimated termination fee of $0.5 million, which is included in the $2.8 million of intangible assets as of December 31, 2006, above.

For each of the years ended December 31, 2006, 2005 and 2004, we recorded amortization expense associated with these commodity contracts of $0.4 million, $0.7 million, and $1.6 million, respectively. As of December 31, 2006, the remaining amortization periods for these contracts range from approximately two to 20 years, with a weighted-average remaining period of approximately 15 years.

Estimated future amortization for these contracts is as follows ($ in millions):

	Year Ended December 31,
2007	$ 0.3
2008	0.2
2009	0.1
2010	0.1
2011	0.1
Thereafter	1.5
Total	$ 2.3

8. Equity Method Investments

We have two investments accounted for using the equity method. The following table includes our percentage of ownership and the carrying value of our investments as of the indicated dates ($ in millions):

	Percentage of Ownership as of December 31,		Carrying Value as of December 31,	
	2006	2005	2006	2005
Black Lake Pipe Line Company	45%	45%	$ 5.7	$ 5.3
Other	50%	50%	0.2	0.2

Black Lake owns a 317-mile NGL pipeline, with a throughput capacity of approximately 40 MBbls/d. The pipeline receives NGLs from a number of gas plants in Louisiana and Texas. There was a deficit between the carrying amount of the investment and the underlying equity of Black Lake of $6.7 million and $7.0 million at December 31, 2006 and 2005, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

Prior to December 7, 2005, DCP Midstream Partners Predecessor held a 50% interest in Black Lake. Upon completion of our initial public offering, DCP Midstream, LLC retained a 5% interest in Black Lake.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Earnings from equity method investments for the years ended December 31, 2006, 2005 and 2004, were $0.3 million, $0.4 million and $0.6 million, respectively. We did not receive any distributions during the years ended December 31, 2006, 2005 and 2004.

The following summarizes financial information of our equity method investments ($ in millions):

	Year Ended December 31,		
	2006	2005	2004
Statements of operations:			
Operating revenue	$ 4.2	$ 3.4	$ 3.3
Operating expenses	(4.7)	(4.0)	(2.5)
Net (loss) income	$ (0.5)	$ (0.6)	$ 0.8

	December 31,	
	2006	2005
Balance sheet:		
Current assets	$ 4.0	$ 4.9
Non-current assets	18.3	17.7
Current liabilities	0.8	0.7
Net assets	$ 21.5	$ 21.9

9. Impairment of Equity Method Investment

In the third quarter of 2004, we recognized an other-than-temporary impairment of our investment in Black Lake totaling $4.4 million as impairment of equity method investment, included in the consolidated statements of operations. This investment was written down to fair value, which was determined based on management s best estimates of discounted future cash flow models. The charge associated with this impairment is recorded in the NGL Logistics segment.

10. Estimated Fair Value of Financial Instruments

We have determined the following fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts. The following summarizes the estimated fair value of financial instruments ($ in millions):

	December 31, 2006		December 31, 2005	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Restricted investments	$ 102.0	$ 102.0	$ 100.4	$ 100.4
Accounts receivable	$ 78.2	$ 78.2	$ 122.2	$ 122.2
Accounts payable	$ 117.3	$ 117.3	$ 138.3	$ 138.3
Unrealized gains (losses) on non-trading derivative and hedging instruments	$ 7.3	$ 7.3	$ 0.4	$ 0.4
Long-term debt	$ 268.0	$ 268.0	$ 210.1	$ 210.1

The fair value of restricted investments, accounts receivable and accounts payable are not materially different from their carrying amounts because of the short term nature of these instruments or the stated rates

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

approximating market rates. Unrealized gains and unrealized losses on mark-to-market and hedging instruments are carried at fair value.

The carrying value of long-term debt approximates fair value, as the interest rate is variable and reflects current market conditions.

11. Debt

Credit Facility with Financial Institutions On December 7, 2005, we entered into a 5-year credit agreement, or the Credit Agreement, providing a $250.0 million revolving and a $100.1 million term loan facility. The unused portion of the revolving credit facility may be used for letters of credit. The Credit Agreement matures on December 7, 2010. The Credit Agreement prohibits us from making distributions of Available Cash to unitholders if any default or event of default (as defined in the Credit Agreement) exists. The Credit Agreement requires us to maintain at all times (commencing with the quarter ended March 31, 2006) a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of less than or equal to 4.75 to 1.0 (and on a temporary basis for not more than three consecutive quarters following the acquisition of assets in the midstream energy business of not more than 5.25 to 1.0); and maintain at the end of each fiscal quarter an interest coverage ratio (defined to be the ratio of adjusted EBITDA, as defined by the Credit Agreement to be earnings before interest, taxes and depreciation and amortization and other non-cash adjustments, for the four most recent quarters to interest expense for the same period) of greater than or equal to 3.0 to 1.0.

The revolving credit facility bears interest at a rate equal to the London Interbank Offered Rate, or LIBOR, plus an applicable margin, which ranges from 0.27% to 1.025%, based on leverage level or credit rating, or at the higher of the federal funds rate plus 0.50% or Wachovia Bank s prime rate plus an applicable margin of 0% to 0.025%, based on leverage level. The weighted-average interest rate on the revolving credit facility was 5.86% at December 31, 2006. The revolving credit facility incurs an annual facility fee of 0.08% to 0.35%, depending on the applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan bears interest at a rate equal to either the London Interbank Offered Rate, or LIBOR, plus 0.15%, the federal funds rate plus 0.5%, or the Wachovia Bank prime rate. The interest rate on the term loan was 5.47% at December 31, 2006.

At December 31, 2006 and 2005, there was $168.0 million and $110.0 million outstanding, respectively, on the revolving credit facility, and $100.0 million and $100.1 million outstanding, respectively on the term loan facility. The term loan facility is fully collateralized by high-grade securities, which are classified as restricted investments on the consolidated balance sheets. As of December 31, 2006 and 2005, $1.1 million and $0.8 million, respectively, was recorded as accrued interest payable in the consolidated balance sheets. We paid $11.1 million in interest and facility fees, net of capitalized interest of $0.4 million, in 2006. We paid $0.5 million of facility fees during 2005. At December 31, 2006 there were $0.2 million letters of credit outstanding. There were no letters of credit outstanding at December 31, 2005. In December 2005, we incurred $0.7 million of debt issuance costs associated with the Credit Agreement. These expenses are deferred as other non-current assets in the consolidated balance sheet and will be amortized over the term of the Credit Agreement.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-term debt at December 31, 2006 and 2005 was as follows ($ in millions):

	Principal Amount	
	2006	**2005**
Revolving credit facility, weighed-average interest rate of 5.86% at December 31, 2006, due December 7, 2010	$ 168.0	$ 110.0
Term loan facility, interest rate of 5.47% at December 31, 2006, due December 7, 2010	100.0	100.1
Total long-term debt	$ 268.0	$ 210.1

12. Partnership Equity and Distributions

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

Definition of Available Cash Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

less the amount of cash reserves established by the general partner to:

provide for the proper conduct of our business;

comply with applicable law, any of our debt instruments or other agreements; or

provide funds for distributions to the unitholders and to our general partner for any one or more of the next four quarters;

plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

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

The incentive distribution rights held by the general partner entitles it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner s incentive distribution rights are not reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Please read the *Distributions of Available Cash during the*

Subordination Period and *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on the general partner s incentive distribution rights.

Class C Units The Class C units have the same liquidation preference, rights to cash distributions and voting rights as the common units. The Class C units will automatically convert to common units once the Class C units represent less than 1% of the total outstanding limited partner units. After two years, if the Class C units are not converted into common units, either automatically or by common unitholder approval, they will receive 115% of the distribution amount for common units.

Subordinated Units All of the subordinated units are held by DCP Midstream, LLC. Our partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to $0.35 per common unit, or the Minimum

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Quarterly Distribution, plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The earliest date at which the subordination period may end is December 31, 2008 and 50% of the subordinated units may convert to common units as early as December 31, 2007. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Distributions of Available Cash during the Subordination Period The partnership agreement requires that we make distributions of Available Cash for any quarter during the subordination period in the following manner:

first, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;

second, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;

third, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter; and

fourth, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.4025 per unit for that quarter (the First Target Distribution);

fifth, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter (the Second Target Distribution);

sixth, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter (the Third Target Distribution); and

thereafter, 50% to all unitholders, pro rata, and 50% to the general partner (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period Our partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

first, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.4025 per unit for that quarter;

second, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter;

third, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter; and

thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In February 2006, we paid a cash distribution of $0.095 per unit, to unitholders of record on February 3, 2006. That distribution represented the pro rata portion of our Minimum Quarterly Distribution of $0.35 per unit for the period December 7, 2005, the closing of our initial public offering, through December 31, 2005. During 2006, we paid additional quarterly cash distributions aggregating $1.135 per unit.

13. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate the effects of the identified risks. In general, we attempt to hedge risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements. We have established a comprehensive risk management policy, or the Risk Management Policy, and a risk management committee, to monitor and manage market risks associated with commodity prices and interest rates. Our Risk Management Policy prohibits the use of derivative instruments for speculative purposes.

Commodity Price Risk Our operations of gathering, processing, and transporting natural gas, and the accompanying operations of transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs, and related products produced, processed, transported or stored.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. To the extent that we carry propane inventories or our sales and supply arrangements are not aligned we are exposed to market variables and commodity price risk. The amount and type of price risk is dependent on the mechanisms and locations for purchases, sales, transportation and storage of propane.

Interest Rate Risk Interest rates on future credit facility draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

Credit Risk In the Natural Gas Services segment, we sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. In the Wholesale Propane Logistics segment, we sell primarily to retail propane distributors. In the NGL Logistics segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC s corporate credit policy. DCP Midstream, LLC s corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC s credit policy and guidelines. The agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Commodity Cash Flow Hedges We executed a series of derivative financial transactions, referred to as swap contracts. In 2005 we entered into natural gas swap contracts with a combined notional volume of approximately 4,000 MMBtu/day for a term of January 2006 through December 2010. These contracts are intended to hedge the risk of weakening natural gas prices. In 2005 we also entered into crude oil swap contracts with a combined notional volume of approximately 650 Bbls/day for a term of January 2006 through December 2010. These contracts are intended to hedge the risk of weakening NGL and condensate prices. In 2006 we entered into crude oil swap contracts with a notional volume of 350 Bbls/day for a term of January 2011 through December 2011. These contracts are intended to hedge the risk of weakening condensate prices. Each of these swap contracts has been designated as a cash flow hedge. As a result of these transactions, we have hedged a significant portion of our expected natural gas and NGL commodity price risk relating to our percentage-of-proceeds gathering and processing contracts through 2010, and of our expected condensate commodity price risk relating to condensate recovered from gathering operations through 2011.

We use natural gas and crude oil swaps to hedge the impact of market fluctuations in the price of NGLs, natural gas and condensate. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is accumulated in AOCI, and the ineffective portion is recorded in the consolidated statements of operations as sales of natural gas, propane, NGLs and condensate. For the years ended December 31, 2006 and 2005, we recognized losses of $0.3 million and gains of $0.3 million, respectively, due to the ineffectiveness of these cash flow hedges. For the year ended December 31, 2006, gains of $2.6 million were reclassified into earnings as a result of settlements. For the year ended December 31, 2006, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring, or due to a derivative no longer qualifying as an effective hedge. All components of each derivative s gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction will be reclassified to the consolidated statements of operations in the same accounts as the item being hedged. As of December 31, 2006 and 2005, there were net deferred gains of $6.9 million and $0.4 million, respectively, related to commodity cash flow hedge derivative contracts in AOCI. As of December 31, 2004, no amounts related to cash flow hedges were deferred in AOCI. As of December 31, 2006, $3.0 million of deferred net gains on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings; however, due to the volatility of the commodities markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings.

Commodity Fair Value Hedges We use fair value hedges to hedge exposure to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) to reduce our exposure to fixed price risk by swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index-based).

For the years ended December 31, 2006, 2005 and 2004, the gains or losses representing the ineffective portion of our fair value hedges were not significant. All components of each derivative s gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted. During the years ended December 31, 2006, 2005 and 2004, there were no firm commitments that no longer qualified as fair value hedge items and, therefore, we did not recognize an associated gain or loss.

Normal Purchases and Normal Sales If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract s fair value in the consolidated financial statements is required until

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas, propane or NGLs in future periods.

Commodity Non-Trading Derivative Activity Our operations of gathering, processing, and transporting natural gas, and the accompanying operations of transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. We occasionally will enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings. We manage our asset-based activities in accordance with our Risk Management Policy which limits exposure to market risk and requires regular reporting to management of potential financial exposure. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

Interest Rate Cash Flow Hedge During 2006, we entered into interest rate swap agreements to hedge the variable interest rate on $125.0 million of the indebtedness outstanding under our revolving credit facility. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheets. For the year ended December 31, 2006, gains of $0.1 million were reclassified into earnings as a result of settlements. As of December 31, 2006, gains of $0.4 million were deferred in AOCI related to these swaps. As of December 31, 2006, $0.4 million of these deferred net gains on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days, and expire on December 7, 2010. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 4.68% to 5.08%, and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

14. Equity-Based Compensation

On November 28, 2005, the board of directors of our General Partner adopted the LTIP for employees, consultants and directors of our General Partner and its affiliates who perform services for us, effective as of December 7, 2005.

Under the LTIP, equity-based instruments may be granted to our key employees. The LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the LTIP. Awards that are

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

canceled, forfeited or are withheld to satisfy the General Partner s tax withholding obligations are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the General Partner s board of directors. We first granted awards under the LTIP during 2006.

Performance Units During the year ended December 31, 2006, we awarded 40,560 phantom LPUs pursuant to the LTIP, or Performance Units, to certain employees. Performance Units generally vest in their entirety at the end of a three year performance period. The number of Performance Units which will ultimately vest range from 0% to 150% of the outstanding Performance Units, depending on the achievement of specified performance targets over a three year period ending on December 31, 2008. The final performance payout is determined by the compensation committee of the board of directors of our General Partner. Each Performance Unit includes a DER, which will be paid in cash at the end of the performance period. We recorded approximately $0.2 million of compensation expense related to the Performance Units during the year ended December 31, 2006. There was no compensation expense related to Performance Units prior to January 1, 2006. At December 31, 2006, there was approximately $0.6 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 2.0 years. The following table presents information related to the Performance Units:

	Units(a)	Grant Date Weighted-Average Price per Unit	Measurement Date Weighted-Average Price per Unit
Outstanding at December 31, 2005		$	
Granted	40,560	$ 26.96	
Forfeited	(17,470)	$ 26.96	
Outstanding at December 31, 2006	23,090	$ 26.96	$ 34.55
Expected to vest	23,090	$ 26.96	$ 34.55

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

IPO Phantom Units In conjunction with our initial public offering, in January 2006 our General Partner s board of directors awarded phantom LPUs, or IPO Phantom Units, to key employees, and to directors who are not officers or employees of affiliates of our General Partner. Of these IPO Phantom Units, 16,700 units will vest upon the three year anniversary of the grant date, and 8,000 units vest ratably over three years. Each IPO Phantom Unit includes a DER, which is paid quarterly in arrears. We recorded approximately $0.4 million of compensation expense related to the IPO Phantom Units during the year ended December 31, 2006. There was no compensation expense related to IPO Phantom Units prior to January 1, 2006. At December 31, 2006, there was approximately $0.5 million of unrecognized compensation expense related to the IPO Phantom Units that is expected to be recognized over a weighted-average period of 1.7 years. The following table presents information related to the IPO Phantom Units:

	Units(a)	Grant Date Weighted-Average Price per Unit	Measurement Date Weighted-Average Price per Unit
Outstanding at December 31, 2005		$	
Granted	35,900	$ 24.05	
Forfeited	(11,200)	$ 24.05	
Outstanding at December 31, 2006	24,700	$ 24.05	$ 34.55
Expected to vest	24,700	$ 24.05	$ 34.55

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The estimate of IPO Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

We intend to settle the awards issued under the LTIP in cash upon vesting. Compensation expense is recognized ratably over each vesting period, and will be remeasured quarterly for all awards outstanding until the units are vested. The fair value of all awards is determined based on the closing price of our common units at each measurement date. During the year ended December 31, 2006, no awards were vested or settled.

15. Income Taxes

We are structured as a master limited partnership, which is a pass-through entity for U.S. income tax purposes. The income tax expense reflected on our consolidated statements of operations is applicable to our wholesale propane logistics business. On December 7, 2005, our wholesale propane logistics business changed its tax structure, which resulted in its activities changing from taxable to non-taxable for United States income tax purposes.

Income tax expense consisted of the following for the years ended December 31, 2005 and 2004 ($ in millions):

	Year Ended December 31,	
	2005	**2004**
Current:		
Federal	$ 3.0	$ 2.0
State	0.8	0.6
Deferred:		
Federal	(0.4)	(0.1)
State	(0.1)	
Total income tax expense	$ 3.3	$ 2.5

A reconciliation of the actual income tax expense and the amount computed by applying the federal statutory rate of 35% to the income before income taxes is as follows ($ in millions):

	Year Ended December 31,	
	2005	**2004**
Federal income tax at statutory rate	$ 3.4	$ 2.1
State income taxes, net of federal benefit	0.6	0.5
Change in tax structure	(0.5)	

Depreciation and amortization		0.4
Net trading margins		(0.4)
Other	(0.2)	(0.1)
Total income tax expense	$ 3.3	$ 2.5

The change in tax structure resulted in the reversal of the net deferred tax liabilities in the year ended December 31, 2005. Accordingly, we had no deferred tax balances as of December 31, 2006 or 2005, and no income tax expense for the year ended December 31, 2006.

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In May 2006, the State of Texas enacted a new margin-based franchise tax into law that replaces the existing franchise tax. This new tax is commonly referred to as the Texas margin tax. Corporations, limited partnerships, limited liability companies, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the new tax. The tax is considered an income tax for purposes of adjustments to the deferred tax liability. The tax is determined by applying a tax rate to a base that considers both revenues and expenses. The Texas margin tax becomes effective for franchise tax reports due on or after January 1, 2008. The tax, which is assessed at 1% of taxable margin apportioned to Texas, will be based on the margin earned during the prior calendar year.

The Texas margin tax is considered an income tax for purposes of calculating the deferred tax liability. GAAP requires that deferred taxes be adjusted upon enactment of new tax law, which occurred in 2006. The deferred tax liabilities associated with the Texas margin tax were insignificant.

16. Net Income per Limited Partner Unit

Our net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner.

EITF 03-6 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock.

EITF 03-6 requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

EITF 03-6 does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds the First Target Distribution Level, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of Available Cash and not earnings. In periods in which our aggregate net income does not exceed the First Target Distribution Level, EITF 03-6 does not have any impact on our calculation of earnings per limited partner unit. During the year ended December 31, 2006, our aggregate net income per limited partner unit exceeded the Second Target Distribution level, and as a result we allocated $1.3 million in additional earnings to the general partner.

Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income, less pro forma general partner incentive distributions under EITF 03-6, by the weighted-average number of outstanding limited partner units during the period.

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The following table illustrates our calculation of net income per limited partner unit ($ in millions):

	Year Ended December 31, 2006	Year Ended December 31, 2005
Net income	$ 33.0	$ 44.5
Less:		
Net loss (income) attributable to predecessor operations	2.3	(39.8)
Net income attributable to the partnership	35.3	4.7
Less: General partner interest in net income	(0.7)	(0.1)
Limited partners interest in net income (see Note 12)	34.6	4.6
Less: Additional earnings allocation to general partner	(1.3)	(1.1)
Net income available to limited partners under EITF 03-6	$ 33.3	$ 3.5
Net income per limited partner unit basic and diluted	$ 1.90	$ 0.20

17. Commitments and Contingent Liabilities

Litigation We are not a party to any significant legal proceedings but are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position, or cash flows.

In June 2006, a DCP Midstream, LLC customer whose plant is served by our Seabreeze pipeline notified DCP Midstream, LLC that off specification NGLs had been received into their facility. Our Seabreeze pipeline transports NGLs owned by DCP Midstream, LLC that are delivered to the customer under the terms of a transportation agreement. The customer sent a letter to DCP Midstream, LLC claiming that the off specification NGLs delivered to their facility caused damage to their plant facility. On December 29, 2006 we entered into a settlement agreement with the customer to settle all our issues regarding this matter, and our portion of the settlement was $0.3 million.

In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of our General Partner, DCP Midstream GP, LP, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which is prior to our acquisition of this asset from DCP Midstream, LLC. El Paso claims damages, including interest, in the amount of $5.7 million in the litigation, the bulk of which stems from audit claims under our commercial contract for historical periods prior to our ownership of this asset. We will only be responsible for potential payments, if any, for claims that involve periods of time after the date we acquired this asset from DCP

Midstream, LLC in December 2005. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Insurance In 2005, DCP Midstream, LLC carried insurance coverage, which included our assets and operations, with an affiliate of Duke Energy. Beginning in 2006, DCP Midstream, LLC elected to carry our property and excess liability insurance coverage with an affiliate of Duke Energy and an affiliate of ConocoPhillips. DCP Midstream, LLC provides our remaining insurance coverage with a third party insurer. DCP Midstream, LLC s insurance coverage includes: (1) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from operations; (2) workers

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) excess liability insurance above the established primary limits for commercial general liability and automobile liability insurance; (5) property insurance covering the replacement value of all real and personal property damage, including damages arising from boiler and machinery breakdowns, windstorms, earthquake, flood damage and business interruption/extra expense; and (6) directors and officers insurance covering our directors and officers for acts related to our activities. All coverages are subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations. Effective August 2006, we contracted with a third party insurer for our property and primary liability insurance coverage.

Environmental The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Indemnification DCP Midstream, LLC has indemnified us for three years after the closing of our initial public offering against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing of our initial public offering, on December 7, 2005. DCP Midstream, LLC s maximum liability for this indemnification obligation is $15.0 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DCP Midstream, LLC has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

Additionally, DCP Midstream, LLC will indemnify us for three years after the closing for losses attributable to title defects, certain retained assets and liabilities (including preclosing legal actions relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DCP Midstream, LLC for all losses attributable to the postclosing operations of the assets contributed to us, to the extent not subject to DCP Midstream, LLC s indemnification obligations. In addition, DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the ongoing pipeline integrity testing occurring from 2005 through 2007. DCP Midstream, LLC has also agreed to indemnify us for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of pipeline integrity testing that occurred in 2006. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Any reimbursements of these expenses from DCP Midstream, LLC will be recognized by us as a capital contribution. Reimbursements related to the Seabreeze pipeline integrity repairs in 2006 were not significant.

Other Commitments and Contingencies We utilize assets under operating leases in several areas of operation. Consolidated rental expense, including leases with no continuing commitment, amounted to

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$11.2 million, $10.3 million, and $1.5 million for the years ended December 31, 2006, 2005 and 2004, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows at December 31, 2006 ($ in millions):

2007	$ 9.7
2008	7.8
2009	5.8
2010	5.1
2011	4.3
Thereafter	10.4
Total minimum rental payments	$ 43.1

18. Business Segments

Our operations are located in the United States and are organized into three reporting segments: (1) Natural Gas Services; (2) Wholesale Propane Logistics; and (3) NGL Logistics.

Natural Gas Services The Natural Gas Services segment consists of the North Louisiana system assets, an integrated gas gathering, compression, treating, processing, and transportation system located in northern Louisiana and southern Arkansas that includes the Minden and Ada natural gas processing plants and gathering systems and the Pelico intrastate natural gas gathering and transportation pipeline.

Wholesale Propane Logistics The Wholesale Propane Logistics segment consists of six owned propane rail terminals located in the Midwest and northeastern United States, one leased propane marine terminal located in Providence, Rhode Island, one propane terminal pipeline under construction in Midland, Pennsylvania and access to several open access pipeline terminals.

NGL Logistics The NGL Logistics segment consists of the Seabreeze and Wilbreeze NGL transportation pipelines, which are located along the Gulf Coast area of southeastern Texas, and a non-operated equity interest in the Black Lake interstate NGL pipeline located in northern Louisiana and southeastern Texas, and regulated by the Federal Energy Regulatory Commission, or FERC. Our equity interest consists of 45% from December 7, 2005 through December 31, 2006, and 50% in 2004 and the period from January 1, 2005 through December 6, 2005. DCP Midstream, LLC owns a 5% interest in Black Lake, effective with the date of our initial public offering, and an affiliate of BP PLC owns the remaining interest and is the operator of Black Lake.

These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment. The accounting policies for the segments are the same as those described in Note 2.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables set forth our segment information.

Year ended December 31, 2006 ($ in millions):

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
Total operating revenue	$ 415.3	$ 375.2	$ 5.3	$	$ 795.8
Gross margin(a)	$ 75.3	$ 16.0	$ 4.1	$	$ 95.4
Operating and maintenance expense	(13.5)	(8.6)	(1.6)		(23.7)
Depreciation and amortization expense	(11.1)	(0.8)	(0.9)		(12.8)
General and administrative expense				(12.9)	(12.9)
General and administrative expense affiliate				(8.1)	(8.1)
Earnings from equity method investments			0.3		0.3
Interest income				6.3	6.3
Interest expense				(11.5)	(11.5)
Net income (loss)	$ 50.7	$ 6.6	$ 1.9	$ (26.2)	$ 33.0
Capital expenditures	$ 6.5	$ 9.4	$ 11.3	$	$ 27.2

Year ended December 31, 2005 ($ in millions):

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
Total operating revenues	$ 592.8	$ 359.8	$ 191.7	$	$ 1,144.3
Gross margin(a)	$ 71.4	$ 21.8	$ 3.8	$	$ 97.0
Operating and maintenance expense	(14.0)	(8.2)	(0.2)		(22.4)
Depreciation and amortization expense	(10.8)	(1.0)	(0.9)		(12.7)
General and administrative expense				(5.1)	(5.1)
General and administrative expense affiliate				(9.1)	(9.1)
Earnings from equity method investments			0.4		0.4
Interest income				0.5	0.5

Interest expense				(0.8)	(0.8)
Income tax expense(b)				(3.3)	(3.3)
Net income (loss)	$ 46.6	$ 12.6	$ 3.1	$ (17.8)	$ 44.5
Capital expenditures	$ 7.9	$ 2.9	$	$	$ 10.8

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Year ended December 31, 2004 ($ in millions):

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
Total operating revenues	$ 353.3	$ 324.5	$ 156.2	$	$ 834.0
Gross margin(a)	$ 53.6	$ 16.5	$ 3.3	$	$ 73.4
Operating and maintenance expense	(13.4)	(6.2)	(0.2)		(19.8)
Depreciation and amortization expense	(11.7)	(2.1)	(0.9)		(14.7)
General and administrative expense				(0.9)	(0.9)
General and administrative expense affiliate				(7.8)	(7.8)
Earnings from equity method investments			0.6		0.6
Impairment of equity method investment			(4.4)		(4.4)
Income tax expense(b)				(2.5)	(2.5)
Net income (loss)	$ 28.5	$ 8.2	$ (1.6)	$ (11.2)	$ 23.9
Capital expenditures	$ 2.8	$ 0.2	$ 0.3	$	$ 3.3

The following table sets forth our total assets segment information ($ in millions):

	December 31, 2006	December 31, 2005
Segment non-current assets:		
Natural Gas Services	$ 147.4	$ 152.8
Wholesale Propane Logistics	50.2	40.4
NGL Logistics	35.1	23.5
Other(d)	109.3	106.8
Total non-current assets	342.0	323.5
Current assets	159.6	206.4
Total assets	$ 501.6	$ 529.9

(a) Gross margin consists of total operating revenues less purchases of natural gas, propane and NGLs. Gross margin is viewed as a non-GAAP measure under the rules of the SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Income tax expense relates to our wholesale propane logistics business, which changed its tax status in December 2005.

(c) Other consists of general and administrative expense, interest income, interest expense and income tax expense.

(d) Other non-current assets not allocable to segments consist of restricted investments, unrealized gains on non-trading derivative and hedging instruments, and other non-current assets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. Quarterly Financial Data (Unaudited)

In November 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC in a transaction among entities under common control. Accordingly, the results of operations by quarter have been retroactively adjusted for to include the results of our wholesale propane logistics business for all periods presented.

Our consolidated results of operations by quarter for the years ended December 31, 2006 and 2005 were as follows ($ in millions, except per unit amounts):

2006	First	Second	Third	Fourth	Total
Total operating revenues	$ 265.4	$ 160.1	$ 162.8	$ 207.5	$ 795.8
Operating income	$ 9.1	$ 9.3	$ 7.3	$ 12.2	$ 37.9
Net income	$ 8.0	$ 8.3	$ 6.1	$ 10.6	$ 33.0
Limited partners interest in net income(a)	$ 5.3	$ 8.6	$ 9.5	$ 11.1	$ 34.6
Basic net income per limited partner unit(a)	$ 0.30	$ 0.47	$ 0.51	$ 0.55	$ 1.90

2005	First	Second	Third	Fourth	Total
Total operating revenues	$ 264.4	$ 202.5	$ 285.0	$ 392.4	$ 1,144.3
Operating income	$ 15.1	$ 7.2	$ 2.7	$ 22.7	$ 47.7
Net income	$ 11.9	$ 7.4	$ 6.0	$ 19.2	$ 44.5
Limited partners interest in net income(b)	$	$	$	$ 4.6	$ 4.6
Basic net income per limited partner unit(b)	$	$	$	$ 0.20	$ 0.20

(a) Total limited partners interest in net income and basic income per limited partner unit excludes the results from our wholesale propane logistics business for the period January 1, 2006 through October 31, 2006. See Note 16.

(b) Total limited partners interest in net income and basic income per limited partner unit is calculated using net income earned by us from December 7, 2005 through December 31, 2005, excluding the results from our wholesale propane logistics business. See Note 16.

Our consolidated results of operations by quarter, excluding our wholesale propane logistics business, for the years ended December 31, 2006 and 2005 were as follows ($ in millions, except per unit amounts):

2006	First	Second	Third	Fourth	Total
Total operating revenues	$ 120.0	$ 95.0	$ 102.0	$	$
Operating income	$ 6.5	$ 9.8	$ 10.9	$	$
Net income	$ 5.4	$ 8.8	$ 9.7	$	$

Limited partners interest in net income	$ 5.3	$ 8.6	$ 9.5	$	$
Basic net income per limited partner unit	$ 0.30	$ 0.47	$ 0.51	$	$

2005	**First**	**Second**	**Third**	**Fourth**	**Total**
Total operating revenues	$ 127.4	$ 150.4	$ 233.1	$ 273.6	$ 784.5
Operating income	$ 6.9	$ 7.7	$ 3.4	$ 19.9	$ 37.9
Net income	$ 7.1	$ 7.8	$ 3.5	$ 19.6	$ 38.0
Limited partners interest in net income	$	$	$	$ 4.6	$ 4.6
Basic net income per limited partner unit	$	$	$	$ 0.20	$ 0.20

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Our combined results of operations by quarter for our wholesale propane logistics business for the years ended December 31, 2006 and 2005 were as follows ($ in millions):

2006	First	Second	Third	Fourth	Total
Total operating revenues	$ 145.4	$ 65.1	$ 60.8	$	$
Operating income	$ 2.6	$ (0.5)	$ (3.6)	$	$
Net income (loss)	$ 2.6	$ (0.5)	$ (3.6)	$	$
Limited partners interest in net income	N/A	N/A	N/A	N/A	N/A
Basic net income per limited partner unit	N/A	N/A	N/A	N/A	N/A

2005	First	Second	Third	Fourth	Total
Total operating revenues	$ 137.0	$ 52.1	$ 51.9	$ 118.8	$ 359.8
Operating income	$ 8.2	$ (0.5)	$ (0.7)	$ 2.8	$ 9.8
Net income (loss)	$ 4.8	$ (0.4)	$ 2.5	$ (0.4)	$ 6.5
Limited partners interest in net income	N/A	N/A	N/A	N/A	N/A
Basic net income per limited partner unit	N/A	N/A	N/A	N/A	N/A

20. Subsequent Events

In March 2007, we entered into a definitive agreement to acquire certain gathering and compression assets located in southern Oklahoma from Anadarko Petroleum Corporation for approximately $180.3 million, subject to customary closing conditions and certain regulatory approvals. We paid an earnest deposit of $9.0 million when we entered into this agreement. If Anadarko Petroleum Corporation terminates because we materially breach our representations, warranties or covenants under this agreement, they may retain this earnest deposit as liquidated damages. This deposit will be applied against the purchase price at closing of this transaction, which is expected in the second quarter of 2007. The remaining purchase price is expected to be funded by the issuance of partnership units and by proceeds from our credit facility.

On January 24, 2007, the board of directors of our General Partner declared a quarterly distribution of $0.43 per unit, payable on February 14, 2007, to unitholders of record on February 7, 2007.

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

There were no changes in or disagreements with accountants on accounting and financial disclosures during the year ended December 31, 2006.

Item 9a. ***Controls and Procedures***

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission s rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of December 31, 2006, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of December 31, 2006, our disclosure controls and procedures were effective. There were no significant changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Annual Report On Internal Control Over Financial Reporting

Our general partner is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance to our management and board of directors of our general partner regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, internal control over financial reporting may not prevent or detect misstatements. 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 policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2006 based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which immediately follows.

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March 14, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream Partners GP, LLC
Denver, Colorado:

We have audited management s assessment, included in the accompanying Management s Annual Report on Internal Control over Financial Reporting, that DCP Midstream Partners, LP and subsidiaries (the Company) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2006, of the Company, and our report dated March 14, 2007, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph relating to the basis of presentation of the consolidated financial statements of DCP Midstream Partners, LP (formerly Duke Energy Field Services, LLC) to retroactively reflect the company s acquisition of the wholesale propane logistics business and the preparation of the portion of the DCP Midstream Partners, LP financial statements attributable to the wholesale propane logistics business from the separate records maintained by DCP Midstream, LLC (formerly Duke Energy Field Services, LLC).

/s/ Deloitte & Touche LLP

Denver, Colorado
March 14, 2007

Item 9b. ***Other Information***

No information was required to be disclosed in a report on Form 8-K, but not so reported, for the quarter ended December 31, 2006.

Part III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Management of DCP Midstream Partners, LP

We do not have directors or officers, which is commonly the case with publicly traded partnerships. Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is wholly-owned by DCP Midstream, LLC. The officers and directors of our General Partner are responsible for managing us. All of the directors of our General Partner are elected annually by DCP Midstream, LLC and all of the officers of our General Partner serve at the discretion of the directors. Unitholders are not entitled to participate, directly or indirectly, in our management or operations.

Board of Directors and Officers

The board of directors of our General Partner that oversees our operations currently has eight members, three of whom are independent as defined under the independence standards established by the New York Stock Exchange. The New York Stock Exchange does not require a listed limited partnership like us to have a majority of independent directors on its general partner s board of directors or to establish a compensation committee or a nominating committee. However, the board of directors of our General Partner has established an audit committee consisting of three independent members of the board, a compensation committee and a special committee to address conflict situations.

Our General Partner s board of directors annually reviews the independence of directors and affirmatively makes a determination that each director expected to be independent has no material relationship with our General Partner, either directly or indirectly as a partner, unitholder or officer of an organization that has a relationship with our General Partner.

The executive officers of our General Partner manage the day-to-day affairs of our business and devote all of their time to our business and affairs. We also utilize employees of DCP Midstream, LLC to operate our business and provide us with general and administrative services.

Meeting Attendance and Preparation

Members of our board of directors attended at least 75% of regular board meetings and meetings of the committees on which they serve, either in person or telephonically. In addition, directors are expected to be prepared for each meeting of the board by reviewing materials distributed in advance.

Directors and Executive Officers

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

Name	Age	Position with DCP Midstream GP, LLC
Jim W. Mogg	58	Chairman of the Board
Mark A. Borer	52	President, Chief Executive Officer and Director
Thomas E. Long	50	Vice President and Chief Financial Officer
Michael S. Richards	47	Vice President, General Counsel and Secretary
Greg K. Smith	40	Vice President, Business Development
William H. Easter III	57	Director
Paul F. Ferguson, Jr.	57	Director
John E. Lowe	48	Director
Derrill Cody	68	Director
Frank A. McPherson	73	Director
Thomas C. Morris	66	Director

Our directors hold office for one year or until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers.

Jim W. Mogg was elected Chairman of the Board of DCP Midstream GP, LLC in August 2005. Mr. Mogg retired from his position as Group Vice President, Chief Development Officer and advisor to the Chairman of Duke Energy in September 2006. Mr. Mogg assumed his former position with Duke Energy in January 2004. He previously served as President and Chief Executive Officer of DCP Midstream, LLC from December 1994 and Chairman, President and Chief Executive Officer of DCP Midstream, LLC from 1999 through December 2003. In these capacities, Mr. Mogg was significantly involved in the development and growth of DCP Midstream, LLC. Mr. Mogg will be retiring from the board of directors of the General Partner in the second quarter of 2007, at which time Mr. Fred J. Fowler will assume the responsibilities of the chairman.

Mark A. Borer was elected President and Chief Executive Officer, and director of DCP Midstream GP, LLC in November 2006. Mr. Borer was previously Group Vice President, Marketing and Corporate Development of DCP Midstream, LLC since July 2004. He previously served as Executive Vice President of Marketing and Corporate Development of DCP Midstream, LLC from May 2002 through July 2004. Mr. Borer served as Senior Vice President, Southern Division of DCP Midstream, LLC from April 1999 through May 2002. Prior to that time, Mr. Borer was Vice President of Natural Gas Marketing for Union Pacific Fuels, Inc.

Thomas E. Long was elected Vice President and Chief Financial Officer of DCP Midstream GP, LLC in September 2005. Mr. Long was previously Vice President of National Methanol Company, Duke Energy s international chemical joint venture, since December 2004. From April 2002 until December 2004, Mr. Long served as Vice President and Treasurer of DCP Midstream, LLC. From April 1, 2000 until April 2002, Mr. Long served as Vice President, Investor Relations of DCP Midstream, LLC. Mr. Long joined Duke Energy in 1979 and served in a variety of positions in accounting, finance, tax, investor relations and business development. Mr. Long is a Certified Public Accountant licensed in the state of Texas.

Michael S. Richards was elected Vice President, General Counsel and Secretary of DCP Midstream GP, LLC in September 2005. Mr. Richards was previously Assistant General Counsel and Assistant Secretary of DCP Midstream, LLC since February 2000. He was previously Assistant General Counsel and Assistant Secretary at KN Energy, Inc. from December 1997 until he joined DCP Midstream, LLC. Prior to that, he was Senior Counsel and Risk Manager at Total Petroleum (North America) Ltd. from 1994 through 1997. Mr. Richards was previously in private practice where he focused on securities and corporate finance.

Greg K. Smith was elected Vice President, Business Development of DCP Midstream GP, LLC in September 2005. Mr. Smith was previously Vice President, Corporate Development of DCP Midstream, LLC since June 2002. From July 1996 until June 2002, Mr. Smith held several positions at DCP Midstream, LLC, including Commercial Director and Senior Attorney. Mr. Smith was previously an attorney with El Paso Natural Gas from 1992 until July 1996.

William H. Easter III was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Easter is Chairman of the Board, President and Chief Executive Officer of DCP Midstream, LLC. Prior to joining DCP Midstream, LLC in January 2004, Mr. Easter served as Vice President of State Government Affairs for ConocoPhillips from 2002 through 2003. From 1998 to 2002, Mr. Easter served as General Manager of the Gulf Coast business unit for Conoco Inc. and from 1992 to 1998 he served as Managing Director and Chief Executive Officer of Conoco Jet Nordic in Stockholm, Sweden.

Paul F. Ferguson, Jr. was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Ferguson was elected Chairman of the audit committee in October 2004. He served as Senior Vice President and Treasurer of Duke Energy from June 1997 to June 1998, when he retired. Mr. Ferguson served as Senior Vice President and Chief Financial Officer of PanEnergy Corp. from September 1995 to June 1997. He held various other financial positions with PanEnergy Corp. from 1989 to 1995 and served as Treasurer of Texas Eastern Corporation from 1988 to 1989.

John E. Lowe was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Lowe is Executive Vice President, Commercial of ConocoPhillips. He has responsibility for the supply and trading operations. Mr. Lowe previously served as Executive Vice President, Planning, Strategy and Corporate Affairs from 2002 until April 2006. He was named to this position after serving as Senior Vice President, Corporate Strategy and Development and was responsible for the forward strategy, development opportunities and public relations functions of Phillips Petroleum Company. He was named to this position in 2001 after serving as Senior Vice President of Planning and Strategic transactions in 2000 and Vice President of Planning and Strategic Transactions in 1999. Lowe currently serves on the board of directors for Chevron Phillips Chemical Company, DCP Midstream, LLC, the Houston Museum of Natural Science and the National Association of Manufacturers. He is a certified public accountant.

Derrill Cody was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. Cody is presently of counsel to the law firm of Tomlinson & O Connell in Oklahoma City, Oklahoma since December 1, 2005. Prior to that he was of counsel to the law firm of McKinney & Stringer, P.C., in Oklahoma City from 1990. Mr. Cody served as executive vice president of Texas Eastern Corporation and chairman and chief executive officer of Texas Eastern Gas Pipeline Company in Houston, Texas. Prior to joining Texas Eastern in 1986, Mr. Cody held executive roles with both Kerr McGee Corporation and Texas Gas Resources Corporation prior to its merger with CSX Corporation. Mr. Cody currently serves on the board of CenterPoint Energy, Inc. and the board of regents of Seminole State College. He also previously served on the boards of Plains Petroleum Company from 1990 until its merger with Barrett Resources Corporation in 1995; and Barrett Resources Corporation from 1995 to 2001.

Frank A. McPherson was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. McPherson retired as chairman and chief executive officer from Kerr McGee Corporation in 1997 after a 40-year career with the company. Mr. McPherson was chairman and chief executive officer of Kerr McGee from 1983 to 1997. Prior to that he served in various capacities in management of Kerr McGee. Mr. McPherson joined Kerr McGee in 1957. Mr. McPherson serves on the boards of Integris Health, Tri Continental Corporation, Seligman Group of Mutual Funds, and several non-profit organizations in Oklahoma. He previously served on the boards of ConocoPhillips, Kimberly Clark Corporation, MAPCO Inc., Bank of Oklahoma, the Federal Reserve Bank of Kansas City, the Oklahoma State University Foundation Board of Trustees and the American Petroleum Institute.

Thomas C. Morris was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. Morris is currently retired, having served 34 years with Phillips Petroleum Company. Mr. Morris served in various capacities with Phillips, including vice president and treasurer and subsequently senior vice president and chief financial officer from

1994 until his retirement in 2001. Mr. Morris served as vice chairman of the board of OK Mozart, is a former member of the executive board of the American Petroleum Institute finance committee and a former member of the Business Development Council of Texas A&M University.

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Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires DCP Midstream GP, LLC s directors and executive officers, and persons who own more than 10% of any class of our equity securities to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of our common units and our other equity securities. Specific due dates for those reports have been established, and we are required to report herein any failure to file reports by those due dates. Directors, executive officers and greater than 10% unitholders are also required by SEC regulations to furnish us with copies of all Section 16(a) reports they file. To our knowledge, based solely on a review of the copies of reports furnished to us and written representations that no other reports were required during the fiscal year ended December 31, 2006, all Section 16(a) filing requirements applicable to such reporting persons were complied with.

Audit Committee

The board of directors of our General Partner has a standing audit committee. The audit committee is composed of three nonmanagement directors, Paul F. Ferguson, Jr. (chairman), Frank A. McPherson and Thomas C. Morris, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. The board has determined that each member of the audit committee is independent under Section 303A.02 of the New York Stock Exchange listing standards and Section 10A(m)(3) of the Securities Exchange Act of 1934, as amended. In making the independence determination, the board considered the requirements of the New York Stock Exchange and our Code of Business Ethics. Among other factors, the board considered current or previous employment with us, our auditors or their affiliates by the director or his immediate family members, ownership of our voting securities, and other material relationships with us. The audit committee has adopted a charter, which has been ratified and approved by the board of directors.

With respect to material relationships, the following relationships are not considered to be material for purposes of assessing independence: service as an officer, director, employee or trustee of, or greater than five percent beneficial ownership in (a) a supplier to the partnership if the annual sales to the partnership are less than one percent of the sales of the supplier; (b) a lender to the partnership if the total amount of the partnership s indebtedness is less than one percent of the total consolidated assets of the lender; or (c) a charitable organization if the total amount of the partnership s annual charitable contributions to the organization are less than three percent of that organization s annual charitable receipts.

Mr. Ferguson has been designated by the board as the audit committee s financial expert meeting the requirements promulgated by the SEC and set forth in Item 401(h) of Regulation S-K of the Securities Exchange Act of 1934 based upon his education and employment experience as more fully detailed in Mr. Ferguson s biography set forth above.

Special Committee

The board of directors of our General Partner has a standing special committee, which is comprised of three nonmanagement directors, Frank A. McPherson (chairman), Paul F. Ferguson, Jr. and Thomas C. Morris. The special committee will review specific matters that the board believes may involve conflicts of interest. The special committee will determine if the resolution of the conflict of interest is fair and reasonable to us. The special committee may also occasionally meet in an executive session without management participation. The members of the special committee may not be officers or employees of our General Partner or directors, officers or employees of its affiliates. Each of the members of the special committee meet the independence and experience standards established by the New York Stock Exchange and the Securities Exchange Act of 1934, as amended. Any matters approved by the special committee 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.

Compensation Committee

The board of directors of our General Partner has a standing compensation committee, which is composed of four directors, Jim W. Mogg (chairman), Derrill Cody, William H. Easter, III and Frank A. McPherson. The compensation committee oversees compensation decisions for the officers of our general partner and administers the long-term incentive plan, selecting individuals to be granted equity-based awards from among those eligible to participate. The compensation committee has adopted a charter, which has been ratified and approved by the board of directors.

Corporate Governance Guidelines and Code of Business Ethics

Our board of directors has adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance.

We have adopted a Code of Business Ethics applicable to the persons serving as our directors, officers (including without limitation, the chief executive officer, chief financial officer and principal accounting officer) and employees, which includes the prompt disclosure to the SEC of a current report on Form 8-K of any waiver of the code for executive officers or directors approved by the board of directors.

Copies of our Corporate Governance Guidelines, our Code of Business Ethics, our Audit Committee Charter and our Compensation Committee Charter are available on our website at *www.dcppartners.com.* Copies of these items are also available free of charge in print to any unitholder who sends a request to the office of the Secretary of DCP Midstream Partners, LP at 370 17th Street, Suite 2775, Denver, Colorado 80202, (303) 633-2921.

Communications by Unitholders

Unitholders may communicate with any and all members of our board, including our nonmanagement directors, by transmitting correspondence by mail or facsimile addressed to one or more directors by name or to the chairman of the board or any committee of the board at the following address and fax number; Name of the Director(s), c/o Secretary, DCP Midstream Partners, LP, 370 17th Street, Suite 2775, Denver, Colorado 80202.

New York Stock Exchange, or NYSE, Annual Certification

On January 25, 2007, Mark A. Borer, our Chief Executive Officer, certified to the NYSE, as required by NYSE rules, that as of January 25, 2007, he was not aware of any violation by us of the NYSE s Corporate Governance Listing Standards.

Report of the Audit Committee

The audit committee oversees our financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The audit committee operates under a written charter approved by the board of directors. The charter, among other things, provides that the audit committee has authority to appoint, retain and oversee the independent auditor. In this context, the audit committee:

- reviewed and discussed the audited financial statements in this annual report on Form 10-K with management, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements;

reviewed with Deloitte & Touche, LLP, our independent auditors, who are responsible for expressing an opinion on the conformity of those audited financial statements with generally accepted accounting principles, their judgments as to the quality and acceptability of our accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards;

received the written disclosures and the letter required by standard No. 1 of the independence standards board (independence discussions with audit committees) provided to the audit committee by Deloitte & Touche, LLP;

discussed with Deloitte & Touche, LLP its independence from management and us and considered the compatibility of the provision of nonaudit service by the independent auditors with the auditors independence;

discussed with Deloitte & Touche, LLP the matters required to be discussed by statement on auditing standards No. 61 (communications with audit committees);

discussed with our internal auditors and Deloitte & Touche, LLP the overall scope and plans for their respective audits. The audit committee meets with the internal auditors and Deloitte & Touche, LLP, with and without management present, to discuss the results of their examinations, their evaluations of our internal controls and the overall quality of our financial reporting;

based on the foregoing reviews and discussions, recommended to the board of directors that the audited financial statements be included in the annual report on Form 10-K for the year ended December 31, 2006, for filing with the Securities and Exchange Commission; and

approved the selection and appointment of Deloitte & Touche, LLP to serve as our independent auditors.

This report has been furnished by the members of the audit committee of the board of directors:

Audit Committee

Paul F. Ferguson, Jr. (Chairman)
Frank A. McPherson
Thomas C. Morris

March 14, 2007

The report of the audit committee in this report shall not be deemed incorporated by reference into any other filing by DCP Midstream Partners, LP under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under such acts.

Item 11. *Executive Compensation*

Compensation Discussion and Analysis

General

As a publicly traded limited partnership, we do not have directors, officers or employees. Instead, our operations are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is a wholly-owned subsidiary of DCP Midstream, LLC.

Our General Partner currently has four executive officers and five additional employees who are solely dedicated to our operations and management. The General Partner has not entered into employment agreements with any of our executive officers. The compensation committee of our General Partner s board of directors establishes the compensation program for these employees.

Compensation Committee

The compensation committee is comprised of directors of our General Partner and currently has four members. The compensation committee s responsibilities include, among other duties, the following:

- annually review and approve Partnership goals and objectives relevant to compensation of the Chief Executive Officer, or the CEO, and other executive officers;
- annually evaluate the CEO s performance in light of the Partnership goals and objectives, and approve the CEO s compensation levels based on this evaluation;
- periodically evaluate the terms and administration of the Partnership s short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with the Partnership s goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO or executive officer compensation; and
- perform other duties as deemed appropriate by the General Partner s board of directors.

Compensation Philosophy

Our compensation program is structured to provide the following benefits:

- Attract, retain and reward talented executive officers and key management employees, by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;

Motivate executive officers and key employees to achieve strong financial and operational performance;

Emphasize performance-based compensation, balancing short-term and long-term results;

Reward individual performance; and

Encourage a long-term commitment to the Partnership by requiring target levels of unit ownership.

Methodology

The compensation committee reviews data from market surveys provided by independent consultants to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation. With respect to executive officer compensation, the compensation committee also considers individual performance, levels of responsibility, skills and experience. In 2006 we engaged the services of Apogee, a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for our executives. The study was based on compensation as reported in the annual reports on Form 10-K for a group of peer companies with a similar tax status, and the 2005 Towers Perrin General Industry Executive Compensation Database, or the Towers Perrin Database. The study was comprised of the following companies: Boardwalk Pipeline Partners, LP, Copano Energy, L.L.C., Crosstex Energy, L.P., Enbridge Energy Partners, LP, Genesis Energy, LP, Magellan Midstream Partners, L.P., MarkWest Energy Partners, LP, ONEOK Partners, L.P., Plains All American Pipeline, L.P., Sunoco Logistics Partners L.P. and Valero L.P. Studies such as this generally include only the most highly compensated officers of the company, which correlates to our executive officers. The results of this study, as well as other factors such as our targeted performance objectives, served as a benchmark for establishing our total direct compensation packages. In order to assess the competitiveness of the total direct compensation packages for our executive officers we used the median amount for peer positions from the Apogee study and the data point that represents the 50^{th} percentile of the market in the Towers Perrin Database.

Components of Compensation

The total annual direct compensation program for executives of the General Partner consists of three components: (1) base salary; (2) an annual short-term cash incentive, or STI, which is based on a percentage of annual base salary; and (3) the present value of an equity-based grant under our long-term incentive plan, or LTIP. Under our compensation structure, the allocation between base salary, STI and LTIP varies depending upon job title and responsibility levels. In 2006 this allocation for our executive officers was as follows:

	Base Salary	**Targeted STI Level**	**Targeted LTIP Level**
CEO	33%	20%	47%
CFO	44%	20%	36%
Vice Presidents	44%	20%	36%

In allocating compensation among these components, we believe the compensation of our executive officers should be more heavily weighted toward performance-based compensation since these individuals have a greater opportunity to influence the Partnership s performance. In making this allocation, we have relied in part on the Apogee study of the companies named above. Each component of compensation is further described below.

Base Salary Base salaries for executives are determined based upon job responsibilities, level of experience, individual performance, and comparisons to the salaries of executives in similar positions obtained from the Apogee study. The goal of the base salary component is to compensate executives at a level that approximates the median salaries of individuals in comparable positions at comparably sized companies in our industry.

The base salaries for executives are generally reevaluated annually as part of our performance review process, or when there is a change in the level of job responsibility. The base salaries paid to our executive officers in fiscal year 2006 are set forth in the Summary Compensation table below.

Annual Short-Term Cash Incentive, or STI Under the STI, annual cash incentives are provided to executives to promote the achievement of performance objectives of the Partnership. Target incentive opportunities for executives under the STI are established as a percentage of base salary. Incentive amounts are intended to provide total cash compensation at the market median for executive officers in comparable positions and markets when target performance is achieved, below the market median when minimum performance is achieved and above the market median when maximum performance is achieved. The Apogee study was used to determine the competitiveness of the incentive opportunity for comparable positions. STI payments are generally paid in cash in March of each year for the prior fiscal year s performance.

In 2006, the STI objectives were initially designed and proposed by the executive officers and presented to the Chairman of the General Partner s board of directors. These objectives were then considered and approved by the compensation committee. In 2006, the STI objectives approved by the compensation committee were divided as follows: (1) a financial objective accounted for 50% of the STI; (2) company objectives accounted for 25% of the STI; and (3) personal objectives accounted for 25% of the STI. The target incentive opportunities for 2006 as a percentage of base salary for the CEO, the CFO, and the Vice Presidents were 60%, 45% and 45%, respectively. All STI objectives are subject to change each year.

The 2006 stated financial objective under the STI was based on the achievement of certain levels of distributable cash flow relative to the forecast in the Partnership s initial public offering. As a publicly traded limited partnership, our performance is generally judged on our ability to pay cash distributions to our unitholders. We use distributable cash flow as the financial objective because we believe it is a useful measure of our ability to make such cash distributions. Accordingly, we believe that establishing a financial objective based on distributable cash flow appropriately encourages and rewards decision-making designed to increase our ability to pay cash distributions. For fiscal year 2006, the payout on the financial objective ranged from 50% if the minimum level of performance was achieved, 100% if the target level of performance was achieved and 200% if the maximum level of performance was achieved. When the performance level falls between these percentages, payout will be determined by straight-line interpolation. For fiscal year 2006, the maximum level of performance, or 200% payout, was achieved on this financial objective.

The 2006 stated company objectives under the STI were based on: (1) achievement of certain levels of per unit distribution growth, excluding distribution growth resulting from the contribution of assets from DCP Midstream, LLC; and (2) establishing and maintaining strong internal controls and accounting accuracy while meeting the performance requirements of the Sarbanes-Oxley Act of 2002. The payout on these company objectives ranged from 50% if the minimum level of performance was achieved, 100% if the target level of performance was achieved and 200% if the maximum level of performance was achieved. When the performance level falls between these percentages, payout will be determined by straight-line interpolation. For fiscal year 2006, the 130% payout level of performance, which was between target and maximum level of performance, was achieved for the per unit distribution growth objective and the 200% payout level of performance, which was the maximum level of performance, was achieved for the internal controls and accounting accuracy objective.

The 2006 stated personal objectives under the STI were based on a number of individual performance objectives for each employee, which included items such as total unitholder return relative to the peer group, establishment of strong corporate governances and execution of growth strategies for earnings and targeted EBITDA additions. The personal objectives were approved by the compensation committee for the CEO, and by the CEO for the other executive officers. The payout on the individual personal objectives ranged from 0% if the minimum level of performance was not achieved, 75% if the minimum level of performance was achieved, 100% if the target level of performance was achieved and 125% if the maximum level of performance was achieved. When the performance level falls between these percentages, payout will be determined by straight-line interpolation. For fiscal year 2006, the aggregate level of performance achieved by the executive officers on their personal objectives ranged from 70% payout to 113% payout.

Long-Term Incentive Plan, or LTIP The long-term incentive compensation program has the objective of providing a focus on long-term value creation and enhancing executive retention. Under our 2006 LTIP program, we make cash payments to each executive officer if certain compound annual growth rates in our distributable cash flow are achieved within a three year period, and such executive officer remains employed with us during this period. We believe this program promotes retention of our executive officers, and focuses our executive officers on the goal of long-term value creation through the long-term growth in our distributable cash flow.

For 2006, the compensation committee awarded our executive officers phantom limited partnership units, or phantom LPUs, which vest in their entirety at the end of a three-year measurement period, or the Performance Period, to the extent the performance measure is achieved during the Performance Period. The initial awards were granted at the first board of directors meeting following the end of the first quarter of 2006. The number of awards granted to our executive officers is set forth in the Grants of Plan Based Awards table below. Award recipients also received the right to receive distribution equivalent rights, or

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DERs, on the number of units earned during the Performance Period. Our practice is to determine the dollar amount of long-term incentive compensation that we want to provide, and to then grant a number of phantom LPUs that have a fair market value equal to that amount on the date of grant, which is based on the closing price of our common units on the New York Stock Exchange on the date of grant. Target long-term incentive opportunities for executives under the plan are established as a percentage of base salary, using the Apogee study data for individuals in comparable positions. The target 2006 long-term incentive opportunities, expressed as a percentage of base salary, for the CEO, the CFO and the Vice Presidents were 140%, 80% and 80%, respectively.

Both the phantom LPUs and the DERs will be paid in cash upon vesting. The amount paid on the phantom LPUs will be based on the product of the number of LPUs earned times the fair market value of our common units on the payment date, which is determined to be the closing sales price of our common units on the vesting date, or, if there is no trading in the common units on such date, on the next preceding date on which there is trading. The amount paid on the DERs will equal the quarterly distributions actually paid during the Performance Period on the number of LPUs earned.

For the phantom LPUs granted in 2006, the performance measure is compound annual growth rate, or CAGR, on distributable cash flow over the Performance Period. This performance measure was initially designed and proposed by the executive officers and presented to the chairman of the General Partner s board of directors. These objectives were then considered and approved by the compensation committee. For the Performance Period, CAGR on distributable cash flow will be measured from a baseline measurement of $1.62 of distributable cash flow per unit, based on $28.3 million of distributable cash flow and 17.5 million units outstanding. If the minimum performance target of 10% CAGR on distributable cash flow is not attained during the Performance Period, none of the phantom LPUs will vest. If the CAGR on distributable cash flow is 10%, 50% of the phantom LPUs will vest. If the CAGR on distributable cash flow is 15%, 100% of the phantom LPUs will vest. If the CAGR on distributable cash flow is 25% or greater, 150% of the phantom LPUs will vest. When the CAGR falls between the 50%, 100% and 150% levels, vesting will be determined by straight-line interpolation. The compensation committee may, in its sole discretion, increase or decrease the percentage of units vesting by up to 25 percentage points to reflect its evaluation of key performance issues that may not be captured by the performance measure.

In the event that any person other than DCP Midstream, LLC and/or an affiliate thereof becomes the beneficial owner of more than 50% of the combined voting power of the General Partner s equity interests prior to the completion of the Performance Period, the phantom LPUs and related DERs will vest pro rata based on the number of days that have lapsed in the Performance Period through the date of the change of control, and the remainder of the LPUs and DERs that do not vest will be forfeited. The vested phantom LPUs and related DERs will be paid in cash. In the event an award recipient s employment is terminated for reasons of death, disability, early or normal retirement, or if the recipient is terminated by the General Partner for reasons other than cause, the recipient (or his estate) will be entitled to a pro rata amount of the award based upon the percentage of the Performance Period the recipient was employed and our performance. Termination of employment for any other reason will result in the forfeiture of any unvested units.

Other Compensation In addition, our executives are eligible to participate in other compensation programs, which include but are not limited to:

IPO Phantom Units In conjunction with our initial public offering, in January 2006 our General Partner s board of directors granted phantom LPUs to key employees, including the executive officers, which vest in their entirety three years following the grant date. Upon vesting, the phantom LPUs will be paid in common units or, at the discretion of the compensation committee, cash based on the fair market value of our common units on the payment date. There is no performance condition associated with these phantom LPUs. Award recipients also receive DERs based on the number of common units awarded, which are paid in cash on a quarterly basis from the date of the initial grant. These phantom LPUs were granted to reward those key employees and executive officers that made significant contributions to our successful initial public offering. The amounts of awards granted to our executive officers are set forth in the Grants of Plan Based Awards table below.

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In the event that any person other than DCP Midstream, LLC and/or an affiliate thereof becomes the beneficial owner of more than 50% of the combined voting power of the General Partner s equity interests prior to the completion of the vesting period, all the phantom LPUs will become fully vested upon such change of control, and will be paid in common units of the Partnership, or in the compensation committee s sole discretion, cash. If cash is paid, the amount will be determined based upon the closing price of the Partnership s common units on the New York Stock Exchange upon such change of control. In the event an award recipient s employment is terminated for reasons of death, disability, early or normal retirement, or if the recipient is terminated by the General Partner for reasons other than cause, the phantom LPUs will immediately vest and the recipient (or his estate) will be entitled to the full amount of the award. Termination of employment for any other reason will result in the forfeiture of any unvested units.

Company Retirement Contributions Employees may elect to participate in the DCP Midstream, LLC 401(k) and Retirement Plan. Under the plan, employees may elect to defer up to 75% of their eligible compensation, or up to the limits specified by the Internal Revenue Service. The Partnership matches the first 6% of eligible compensation contributed by the employee to the plan. In addition, the Partnership makes retirement contributions equal to 4% of the eligible compensation of qualifying participants to the plan, up to the limits specified by the Internal Revenue Service. Effective January 1, 2007, the Partnership will make retirement contributions ranging from 4% to 7% of eligible compensation of all employees, based on years of service.

Miscellaneous Compensation Our executive officers are eligible to participate in a nonqualified deferred compensation program. Executive officers are allowed to defer up to 75% of their base salary, and up to 100% of their STI, LTIP or other compensation. Executive officers elect either to receive amounts contributed during specific plan years as a lump sum at a specific date, subject to Internal Revenue Service rules, or in a lump sum or annual annuity (over three to 20 years) at termination.

Executive officers and other eligible employees may participate in a noncontributory, defined benefit retirement plan. Benefits earned under this plan are attributable to compensation in excess of the annual compensation limits under section 401(k) of the Internal Revenue Code. Under this plan, the Partnership makes a contribution of up to 10% of eligible compensation, as defined by this plan, to the nonqualified deferred compensation program.

In addition, we provide our employees, including the executive officers, with a variety of health and welfare benefit programs. The health and welfare programs are intended to protect employees against catastrophic loss and promote well being. These programs include medical, wellness, pharmacy, dental, vision, life insurance premiums, and accidental death and disability. In addition, we pay certain perquisites to our executives, which include items such as financial planning, club dues and an allowance towards annual medical expenses. Finally, we provide all our employees with a monthly parking pass or a pass to be used on available public transportation systems.

Other

Unit Ownership Guidelines To underscore the importance of linking executive and unitholder interests, the board of directors of our General Partner has adopted unit ownership guidelines for executive officers and key employees who are eligible to receive long-term incentive awards. To that extent, the board has established target equity ownership obligations for the various levels of executives, which have a five-year build term. Ownership is reported annually to the compensation committee. As of December 31, 2006, the unit ownership guidelines for the executive officers were as follows:

	Number of Units

CEO	28,000
CFO	10,000
Vice Presidents	10,000

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Report of the Compensation Committee

We have reviewed and discussed with management the Compensation Discussion and Analysis sections above. Based on this review and discussion, we recommended to the board of directors of the General Partner that the Compensation Discussion and Analysis referred to above be included in this annual report on Form 10-K for the year ended December 31, 2006.

Compensation Committee

Jim W. Mogg (Chairman)
Derrill Cody
William H. Easter III
Frank A. McPherson

Executive Compensation

The following table discloses the compensation of the General Partner s principal executive officers, principal financial officer and named executive officers, or collectively, the executive officers , for the year ended December 31, 2006:

Summary Compensation

Name and Principal Position	Year	Salary	LPU Awards(c)	Non-Equity Incentive Plan Compensation	Change in Nonqualified Deferred Compensation Earnings(d)	All Other Compensation(e)	Total
Michael J. Bradley(a) *Former President and Chief Executive Officer*	2006	$ 291,497	$ (f)	$ (f)	$ 4,427	$ 68,410	$ 364,334
Mark A. Borer(b) *President and Chief Executive Officer*	2006	$ 47,215	$	$ 46,655	$ 45	$ 2,052	$ 95,967
Thomas E. Long *Vice President and Chief Financial Officer*	2006	$ 180,000	$ 92,191	$ 133,650	$	$ 33,182	$ 439,023
Michael S. Richards *Vice President, General Counsel and Secretary*	2006	$ 165,000	$ 88,390	$ 122,048	$	$ 32,717	$ 408,155
Greg K. Smith *Vice President, Business Development*	2006	$ 170,000	$ 89,600	$ 121,444	$ 480	$ 36,044	$ 417,568

(a) Mr. Bradley s employment with the General Partner terminated effective October 31, 2006.

(b) Mr. Borer s employment with the General Partner commenced effective November 10, 2006.

(c) The amounts in this column reflect the dollar amount recognized for financial statement reporting purposes for the year ended December 31, 2006, in accordance with the provisions of Statement of Financial Standards No. 123, *Share-Based Payment*, as revised, or SFAS 123R, and include amounts from awards granted in January 2006 related to our initial public offering, and awards granted in conjunction with our LTIP during 2006. See Note 14 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

(d) Amounts in this column are also included in the Nonqualified Deferred Compensation table below.

(e) Includes DERs, company retirement and nonqualified deferred compensation program contributions by the Partnership, the value of life insurance premiums paid by the Partnership on behalf of an executive, and other deminimus compensation.

(f) Forfeited effective with the resignation from the General Partner.

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Michael J. Bradley, Former President and CEO

Prior to his resignation, Mr. Bradley was receiving an annual base salary of $336,500, of which he deferred $23,320 of the amounts earned in 2006. Mr. Bradley forfeited all of his phantom LPU awards, which were valued at $177,874 for financial statement reporting purposes for the year ended December 31, 2006, in accordance with the provisions of SFAS 123R, effective with his resignation from the General Partner on October 31, 2006. Additionally, Mr. Bradley forfeited the unvested DERs related to the phantom LPUs granted pursuant to the 2006 LTIP, which were valued at $12,753, in accordance with the provisions of SFAS 123R. Under the STI, Mr. Bradley was eligible to earn a targeted level of 60% of his annual base salary, which he also forfeited effective with his resignation from the General Partner.

All Other Compensation includes the following:

Company retirement contributions of $22,000;

Nonqualified deferred compensation program contributions of $31,648;

DERs of $5,940;

Life insurance premiums of $1,057 paid by the Partnership on behalf of Mr. Bradley; and

Payout of vacation accrued as of October 31, 2006, of $7,765.

Mark A. Borer, President and CEO

The annual base salary for 2006 for Mr. Borer was $341,000, of which he deferred $8,944 of the amount of $47,215 earned for his service with the Partnership in 2006. Under the 2006 STI, Mr. Borer s target opportunity was 60% of his annual base salary, with the possibility of earning from 0% to 109% of his annual base salary, depending on the level of performance in each of the STI objectives, which was pro rated based upon his service period for 2006. While an employee at DCP Midstream, LLC, he received various equity grants and other compensation which are not reflected as part of the compensation attributable to his service with the Partnership.

All Other Compensation includes the following:

Nonqualified deferred compensation program contributions of $1,945; and

Life insurance premiums of $107 paid by the Partnership on behalf of Mr. Borer.

Thomas E. Long, Vice President and CFO

The annual base salary for Mr. Long was $180,000 of which none was deferred in 2006. The LPU awards are comprised of IPO Phantom Units and phantom LPUs pursuant to the LTIP. Under the 2006 STI, Mr. Long s target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 82% of his annual base salary, depending on the level of performance in each of the STI objectives.

All Other Compensation includes the following:

Company retirement contributions of $21,553;

DERs of $10,981; and

Life insurance premiums of $648 paid by the Partnership on behalf of Mr. Long.

Michael S. Richards, Vice President, General Counsel and Secretary

The annual base salary for Mr. Richards was $165,000 of which none was deferred in 2006. The LPU awards are comprised of IPO Phantom Units and phantom LPUs pursuant to the LTIP. Under the 2006 STI, Mr. Richards target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 82% of his annual base salary, depending on the level of performance in each of the STI objectives.

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All Other Compensation includes the following:

- Company retirement contributions of $20,891;
- DERs of $10,482;
- Life insurance premiums of $594 paid by the Partnership on behalf of Mr. Richards; and
- A deminimus bonus of $750.

Greg K. Smith, Vice President, Business Development

The annual base salary for Mr. Smith was $170,000 of which he deferred $6,800 of the amounts earned in 2006. The LPU awards are comprised of IPO Phantom Units and phantom LPUs pursuant to the LTIP. Under the 2006 STI, Mr. Smith s target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 82% of his annual base salary, depending on the level of performance in each of the STI objectives.

All Other Compensation includes the following:

- Company retirement contributions of $21,928;
- Nonqualified deferred compensation program contributions of $2,864;
- DERs of $10,640; and
- Life insurance premiums of $612 paid by the Partnership on behalf of Mr. Smith.

Grants of Plan-Based Awards

Following are the grants of plan-based awards for the General Partner s executive officers as of December 31, 2006:

		Estimated Future Payouts under Non-Equity Incentive Plan Awards(a)			Estimated Future Payouts under Equity Incentive Plan Awards			
Name	**Grant Date**	**Minimum ($)**	**Target ($)**	**Maximum ($)**	**Minimum (#)**	**Target (#)**	**Maximum (#)**	**Grant Date Fair Value of LPU Awards ($)**
Mark A. Borer(c)	NA	$ 15,935	$ 28,329	$ 51,346				$
Thomas E. Long	NA	$ 45,563	$ 81,000	$ 146,813				

	1/3/2006				4,000	4,000	4,000	$ 96,200
	5/5/2006(b)				2,670	5,340	8,010	$ 143,966
Michael S. Richards	NA	$ 41,766	$ 74,250	$ 134,578				
	1/3/2006				4,000	4,000	4,000	$ 96,200
	5/5/2006(b)				2,450	4,900	7,350	$ 132,104
Greg K. Smith	NA	$ 43,031	$ 76,500	$ 138,656				
	1/3/2006				4,000	4,000	4,000	$ 96,200
	5/5/2006(b)				2,520	5,040	7,560	$ 135,878

(a) Amounts shown represent amounts under the STI. If minimum levels of performance are not met, then the payout for one or more of the components of the STI may be zero.

(b) The number of units shown on the line with the grant date of 5/5/2006 represent units awarded under the 2006 LTIP. If minimum levels of performance are not met, then the payout may be zero.

(c) Prorated based on period of service for 2006.

The IPO Phantom Units were awarded on January 3, 2006, and will vest in their entirety on January 3, 2009. The phantom LPUs pursuant to the 2006 LTIP were awarded on May 5, 2006, and will vest in their

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entirety on December 31, 2008, if the specified performance conditions are satisfied. Mr. Bradley forfeited all of his IPO Phantom Unit awards and the phantom LPU awards pursuant to the 2006 LTIP upon his resignation from the General Partner on October 31, 2006.

Outstanding Equity Awards at Fiscal Year-End

Following are the outstanding equity awards for the General Partner s executive officers as of December 31, 2006:

	Outstanding LPU Awards					
Name	**Units That Have Not Vested(a)**		**Market Value of Units That Have Not Vested(b)**	**Equity Incentive Plan Awards: Unearned Units That Have Not Vested(c)**		**Equity Incentive Plan Awards: Market Value of Unearned Units That Have Not Vested(b)**
Thomas E. Long	4,000	$	138,200	5,340	$	184,497
Michael S. Richards	4,000	$	138,200	4,900	$	169,295
Greg K. Smith	4,000	$	138,200	5,040	$	174,132

(a) IPO Phantom Units awarded 1/3/2006; units vest in their entirety on 1/3/2009. For additional information, see Compensation Discussion and Analysis Other Compensation IPO Phantom Units.

(b) Value calculated based on the closing price of a common LPU at December 29, 2006.

(c) Phantom LPUs pursuant to the 2006 LTIP awarded 5/5/2006; units vest in their entirety over a range of 0% to 150% on 12/31/2008 if the specified performance conditions are satisfied; valuation of unvested units is based on assumed performance at target performance levels.

Options Exercises and Stock Vested

There were no options exercised and no limited partnership units that vested during the year ended December 31, 2006.

Nonqualified Deferred Compensation

Following is the nonqualified deferred compensation for the General Partner s executive officers for the year ended December 31, 2006:

Executive Contributions in Last Fiscal	Registrant Contributions in Last Fiscal	Aggregate Earnings in Last Fiscal	Aggregate Withdrawals/	Aggregate Balance at December 31,

Name	Year(a)(b)	Year(b)	Year(c)	Distributions(d)	2006(d)
Michael J. Bradley	$ 23,320	$	$ 33,480	$ 318,831	$ 84,243
Mark A. Borer	$ 8,944	$	$ 24,651	$	$ 480,389
Greg K. Smith	$ 6,800	$	$ 885	$	$ 20,582

(a) These amounts were included in the gross salary reported in the Salary column of the Summary Compensation table.

(b) We have not included Executive Contributions or Registrant Contributions attributable to the executive officers prior service with our parent company, DCP Midstream, LLC (their former employer).

(c) Amounts attributable to 2006 contributions are included in the Summary Compensation table as Change in Nonqualified Deferred Compensation Earnings. The remaining amounts are earnings on contributions attributable to the executive officers prior service with our parent company, DCP Midstream, LLC (their former employer).

(d) Includes amounts attributable to the executive officers service with the Partnership, as well as their prior service with our parent company, DCP Midstream, LLC (their former employer).

Executive officers are allowed to defer up to 75% of their base salary, and up to 100% of their STI, LTIP or other compensation. Executive officers elect either to receive amounts contributed during specific plan years as a lump sum at a specific date, subject to Internal Revenue Service rules, or in a lump sum or annual annuity (over three to 20 years) at termination.

Potential Payments Upon Termination or Change in Control

As noted above, the General Partner has not entered into any employment agreements with any of our executive officers. There are no formal severance plans in place for any employees in the event of termination of employment, or a change in control of the Partnership. When an employee terminates employment with the Partnership, they are entitled to a cash payment for the amount of unused vacation hours at the date of their termination.

Compensation of Directors

General On February 8, 2006, the board of directors of the General Partner approved a compensation package for directors who are not officers or employees of affiliates of the General Partner, or Non-Employee Directors. Members of the board who are also officers or employees of affiliates of the General Partner do not receive additional compensation for serving on the board. The board approved the payment to each Non-Employee Director of an annual compensation package containing the following: (1) a $35,000 retainer; (2) a board meeting fee of $1,000 for each board meeting attended; (3) a telephonic board meeting fee of $500 for each telephonic meeting attended; (4) an initial grant of 2,000 phantom LPUs, under the LTIP, that represent an approximate equivalent value of common units representing LPUs in the Partnership; and (5) following the first year, an annual grant of 1,000 common LPUs. The directors also receive DERs, based on the number of units awarded, which are paid in cash on a quarterly basis. The phantom LPUs will vest ratably over three years. The phantom LPUs will be paid in cash upon vesting, based on fair market value on the payment date, which is determined to be the closing sales price of a common unit of the Partnership on the vesting date, or, if there is no trading in the units on such date, on the next preceding date on which there was trading.

Our directors will also be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors and committees. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Committees The chairman of the audit committee of the board will receive an annual retainer of $20,000 and the members of the audit committee will receive $1,500 for each audit committee meeting attended. The chairman of the special committee of the board will likewise receive an annual retainer of $20,000 and the members of the special committee will receive $1,000 for each special committee meeting attended. Finally, the members of the compensation committee will receive $1,000 for each compensation committee meeting attended.

Following is the compensation of the General Partner s Non-Employee Directors for the year ended December 31, 2006:

Name	Fees Earned or Paid in Cash	LPU Awards(d)	All Other Compensation(e)	Total
Jim W. Mogg(a)	$ 40,000	$	$ 1,275	$ 41,275
Paul F. Ferguson, Jr.	$ 85,500	$ 42,237	$ 8,022	$ 135,759

Frank A. McPherson	$	87,000	$	42,237	$	4,966	$	134,203
Thomas C. Morris	$	65,500	$	42,237	$	6,896	$	114,633
Milton Carroll(b)	$	52,000	$		$	3,659	$	55,659
Derrill Cody	$	45,500	$	42,237	$	3,577	$	91,314
Michael J. Panatier(c)	$	41,500	$		$	2,460	$	43,960

(a) Chairman of the board of directors of the General Partner; compensation prorated from September 1, 2006.

(b) Mr. Carroll resigned from the board of directors of the General Partner effective December 20, 2006.

(c) Mr. Panatier resigned from the board of directors of the General Partner effective November 27, 2006.

(d) The amounts in this column reflect the dollar amount recognized for financial statement reporting purposes for the year ended December 31, 2006, in accordance with the provisions of SFAS 123R, and include amounts from awards granted in conjunction with our LTIP during 2006. See Note 14 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

(e) Includes DERs, and reimbursement for out-of-pocket expenses in connection with attending meetings.

On November 29, 2006, the board of directors of the General Partner approved a compensation package for Jim W. Mogg, the chairman of the board of directors. Mr. Mogg, who retired from Duke Energy Corporation in September 2006, will receive an annual retainer of $120,000, which was prorated for 2006 and will continue for 2007. Mr. Mogg is not eligible for additional compensation for attending board meetings or committee meetings that our other Non-Employee Directors are eligible to receive. Mr. Mogg is also the compensation committee chair. He received no additional compensation for serving in that capacity during 2006. Mr. Mogg will be retiring from the board of directors of the General Partner in the second quarter of 2007, at which time Mr. Fred J. Fowler will assume the responsibilities of the chairman.

Mr. Ferguson is the audit committee chair and a member of the special committee.

Mr. McPherson is the special committee chair, and a member of the audit committee and the compensation committee.

Mr. Morris is a member of the audit committee and the special committee.

Mr. Carroll was a member of the compensation committee and the special committee. The value of Mr. Carroll s phantom LPU awards, calculated in accordance with the provisions of SFAS 123R, was $41,321 as of the date of his resignation.

Mr. Cody is a member of the compensation committee.

Mr. Panatier was a member of the compensation committee. The value of Mr. Panatier s phantom LPU awards, calculated in accordance with the provisions of SFAS 123R, was $40,330 as of the date of his resignation.

The total grant date fair value of phantom LPU awards for the Non-Employee Directors was $288,600, of which $96,200 was forfeited by Messrs. Carroll and Panatier upon their respective resignations from the board of directors. At December 31, 2006, Messrs. Cody, Ferguson, McPherson and Morris each had 2,000 phantom LPUs outstanding, related to awards granted in 2006.

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

The following table sets forth the beneficial ownership of our units and the related transactions held by:

each person who beneficially owns 5% or more of our outstanding units as of March 12, 2007;

all of the directors of DCP Midstream GP, LLC;

each Named Executive Officer of DCP Midstream GP, LLC; and

all directors and Named Executive Officers of DCP Midstream GP, LLC as a group.

Percentage of total common, Class C and subordinated units beneficially owned is based on 17,700,312 units outstanding.

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Name of Beneficial Owner(a)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Class C Units Beneficially Owned	Percentage of Class C Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common, Class C and Subordinated Units Beneficially Owned
DCP Midstream, LLC(b)(1)	7,143	*	200,312	100%	7,142,857	100%	41.5%
DCP LP Holdings, LP(c)(1)	7,143	*	200,312	100%	7,142,857	100%	41.5%
Fiduciary Asset Management, L.L.C.(d)	971,640	9.4%					5.5%
Williams, Jones & Associates, LLC(e)	968,174	9.4%					5.5%
Jim W. Mogg	13,001	*					*
Mark A. Borer	32,001	*					*
Thomas E. Long	22,501	*					*
Michael S. Richards	1,501	*					*
Greg K. Smith	5,001	*					*
William H. Easter III	3,501	*					*
Paul F. Ferguson, Jr.	1,001	*					*
John E. Lowe	10,001	*					*
Derrill Cody	15,001	*					*
Frank A. McPherson	5,001	*					*
Thomas C. Morris	5,001	*					*
All directors and executive officers as a group (11 persons)	113,511	*					*

* Less than 1%.

(a) Unless otherwise indicated, the address for all beneficial owners in this table is 370 17th Street, Suite 2775, Denver, Colorado 80202.

(b) DCP Midstream, LLC is the ultimate parent company of DCP LP Holdings, LP and may, therefore, be deemed to beneficially own the units held by DCP LP Holdings, LP. DCP Midstream, LLC disclaims beneficial ownership of all of the units owned by DCP LP Holdings, LP. The address of DCP Midstream, LLC is 370 17th Street, Suite 2500, Denver, Colorado 80202.

(c) The address of DCP LP Holdings, LP is 370 17th Street, Suite 2500, Denver, Colorado 80202.

(d) As set forth in a Schedule 13G filed on January 10, 2007. The address of Fiduciary Asset Management, L.L.C. is 8112 Maryland Avenue, Suite 400, St. Louis, MO 63105. Fiduciary Asset Management, L.L.C. acts as an investment sub-advisor to certain closed-end investment companies, as well as to private individuals, some of whom may be deemed to be beneficial owners.

(e) As set forth in a Schedule 13G filed on February 14, 2007. The address of Williams, Jones & Associates, LLC is 717 Fifth Avenue, New York, New York 10022.

Equity Compensation Plan Information

The following table summarizes information about our equity compensation plan as of December 31, 2006.

	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights(1) (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a)) (c)
Equity compensation plans approved by unitholders		$	
Equity compensation plans not approved by unitholders			802,210
Total		$	802,210

(1) The long-term incentive plan currently permits the grant of awards covering an aggregate of 850,000 units. For more information on our long-term incentive plan, which did not require approval by our limited partners, refer to Item 11. Executive Compensation Components of Compensation.

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

Distributions and Payments to our General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our formation, ongoing operation, and liquidation. These distributions and payments are determined by and among affiliated entities and, consequently, are not the result of arm s-length negations.

Operational Stage:	
Distributions of Available Cash to our General Partner and its affiliates	We will generally make cash distributions 98% to the unitholders and 2% to our General Partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level.

Payments to our General Partner and its affiliates	We reimburse DCP Midstream, LLC and its affiliates up to $6.8 million per year, adjusted annually commencing in 2007, by changes in the Consumer Price Index, for the provision of various general and administrative services for our benefit. For further information regarding the reimbursement, please see the Omnibus Agreement section below.
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.

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Omnibus Agreement

The employees supporting our operations are employees of DCP Midstream, LLC. We are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. DCP Midstream, LLC also provides centralized corporate functions on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. Our Omnibus Agreement, as amended, clarifies that the annual fee of $6.8 million under the agreement is fixed at such amount, subject to annual increases in the Consumer Price Index, and increases in connection with the expansion of our operations through the acquisition or construction of new assets or businesses.

Our Omnibus Agreement with DCP Midstream, LLC, our General Partner and others addresses the following matters:

- our obligation to reimburse DCP Midstream, LLC for the payment of operating expenses, including salary and benefits of operating personnel, it incurs on our behalf in connection with our business and operations;

- our obligation to reimburse DCP Midstream, LLC for providing us with general and administrative services with respect to our business and operations, which is $6.8 million, subject to an increase for 2007 and 2008 based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of our special committee;

- our obligation to reimburse DCP Midstream, LLC for insurance coverage expenses it incurs with respect to our business and operations and with respect to director and officer liability coverage;

- DCP Midstream, LLC s obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities;

- DCP Midstream, LLC s obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements were in effect as of the closing of our initial public offering until the earlier to occur of the fifth anniversary of the closing of our initial public offering or such time as we obtain an investment grade credit rating from either Moody s Investor Services, Inc. or Standard & Poor s Ratings Group with respect to any of our unsecured indebtedness; and

- DCP Midstream, LLC s obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to our business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts.

Our General Partner and its affiliates will also receive payments from us pursuant to the contractual arrangements described below under the caption Contracts with Affiliates.

Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions described below, will be terminable by DCP Midstream, LLC 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, our general partner (DCP Midstream GP, LP) or our General Partner (DCP Midstream GP, LLC).

Competition

None of DCP Midstream, LLC nor any of its affiliates, including Spectra Energy and ConocoPhillips, is restricted, under either our partnership agreement or the Omnibus Agreement, from competing with us. DCP

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Midstream, LLC and any of its affiliates, including Spectra Energy and ConocoPhillips, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the Omnibus Agreement, DCP Midstream, LLC will indemnify us for three years after the closing of our initial public offering against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing date of our initial public offering. DCP Midstream, LLC s maximum liability for this indemnification obligation does not exceed $15 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DCP Midstream, LLC has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

Additionally, DCP Midstream, LLC will indemnify us for losses attributable to title defects, retained assets and liabilities (including preclosing litigation relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DCP Midstream, LLC for all losses attributable to the postclosing operations of the assets contributed to us, to the extent not subject to DCP Midstream, LLC s indemnification obligations. In addition, DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from 2005 through 2007. DCP Midstream, LLC has also agreed to indemnify us for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of pipeline integrity testing that occurred in 2006. Reimbursements related to the Seabreeze pipeline integrity repairs in 2006 were not significant.

Contracts with Affiliates

We charge transportation fees, sell a portion of our residue gas and NGLs to, and purchase raw natural gas and NGLs from, DCP Midstream, LLC, ConocoPhillips, and their respective affiliates. Management anticipates continuing to purchase and sell these commodities to DCP Midstream, LLC, ConocoPhillips and their respective affiliates in the ordinary course of business.

Natural Gas Gathering and Processing Arrangements

We have a fee-based contractual relationship with ConocoPhillips, which includes multiple contracts, pursuant to which ConocoPhillips has dedicated all of its natural gas production within an area of mutual interest to our Ada, Minden and Pelico systems under multiple agreements that have terms of up to five years and are market based. These agreements provide for the gathering, processing and transportation services at our Ada and Minden gathering and processing systems and the Pelico system. At our Ada gathering and processing system, we collect fees from ConocoPhillips for gathering and compressing the natural gas from the wellhead or receipt point and processing the natural gas at the Ada processing plant. At our Minden gathering and processing system, we purchase natural gas from ConocoPhillips at the wellhead or receipt point, transport the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs at index prices based on published index market prices. At our Pelico system, we collect fees for compression and transportation services. Please read Business Natural Gas Services Segment Customers and Contracts and DCP Midstream Partners, LP Notes to Consolidated Financial Statements Agreements and Transactions with Affiliates.

One of these arrangements is set forth in a natural gas gathering agreement dated June 1, 1987, as amended, between DCP Assets Holding, LP (successor to the interest of Cornerstone Natural Gas Company) and ConocoPhillips (successor to interest of Phillips Petroleum Company). We succeeded to the rights and obligations of DCP Assets Holding, LP under this agreement upon the closing of our initial public offering.

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Pursuant to this agreement, we receive gathering and compression fees from ConocoPhillips with respect to natural gas produced by ConocoPhillips that we gather and compress in our Ada gathering system from wells located in a designated area of mutual interest located in northern Louisiana covering approximately 54 square miles. The fees we receive are based on market rates for these types of services. To date, ConocoPhillips has drilled and connected approximately 145 wells to our Ada gathering system pursuant to this contract. This agreement expires in 2011.

Merchant Arrangements

Under our merchant arrangements, we use a subsidiary of DCP Midstream, LLC (DCP Midstream Marketing, LP) as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas primarily to third parties. In the case of certain industrial end-user customers, from time to time we may sell aggregated natural gas to a subsidiary of DCP Midstream, LLC, which in turn would resell natural gas to these customers. Under these arrangements, we expect that this subsidiary of DCP Midstream, LLC would make a profit on these sales. We have also entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that requires DCP Midstream, LLC to supply Pelico s system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index-based price less a contractually agreed to marketing fee. In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments. We also sell our NGLs at the Minden processing plant to a subsidiary of DCP Midstream, LLC (Duke Energy NGL Services, LP) who then transports the NGLs on the Black Lake pipeline. We have also entered into a fixed price natural gas purchase arrangement with a third party customer. In connection with this third party arrangement, we have also entered into a financial hedging arrangement with a subsidiary of DCP Midstream, LLC (DCP Midstream Marketing, LP). Under this hedging arrangement, we have reduced the fixed price risk related to the third party arrangement. These arrangements settled in March 2006. Please read DCP Midstream Partners, LP Notes to Consolidated Financial Statements Agreements and Transactions with Affiliates.

Transportation Arrangements

Effective December 2005, we entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC (DCP NGL Services, LP) that provided that the DCP Midstream, LLC subsidiary will pay us to transport NGLs on our Seabreeze pipeline pursuant to a fee-based rate that will be applied to the volumes transported. This fee-based contract, as amended, is a 17-year transportation agreement expiring in 2022. Under this agreement, we are required to reserve sufficient capacity in the Seabreeze pipeline to ensure our ability to accept up to 38,000 Bbls/d of NGLs tendered by the DCP Midstream, LLC subsidiary each day prior to utilizing the excess capacity for our own use or for that of any third parties, and the DCP Midstream, LLC subsidiary is required to tender all NGLs processed at certain plants that it owns, controls or otherwise has an obligation to market for others. DCP Midstream, LLC historically is also the largest shipper on the Black Lake pipeline, primarily due to the NGLs delivered to it from our Minden processing plant. Please read DCP Midstream Partners, LP Notes to Consolidated Financial Statements Agreements and Transaction with Affiliates.

Hedging Arrangements

We have entered into long-term natural gas and crude oil swap contracts whereby we receive a fixed price for natural gas and crude oil and we pay a floating price. DCP Midstream, LLC has issued guarantees to our counterparties in those transactions that were in effect at the time of our initial public offering. With this credit support, we have more favorable collateral terms than we would have otherwise received. For more information regarding our hedging activities and credit support provided by DCP Midstream, LLC, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies and Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Other Agreements and Transactions with DCP Midstream, LLC

In December 2006, we completed construction of our Wilbreeze pipeline, which connects a DCP Midstream, LLC gas processing plant to our Seabreeze pipeline. The project is supported by a 10-year NGL product dedication agreement with DCP Midstream, LLC.

In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for capital projects, which were forecasted to be completed prior to our initial public offering, but were not completed by that date. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $3.4 million during 2006, to reimburse us for the capital costs we incurred, primarily for growth capital projects. At December 31, 2006, all of these projects were completed.

Director Independence

Please see Item 10. Directors, Executive Officers and Corporate Governance for information about the independence of our general partner s board of directors and its committees, which information is incorporated herein by reference in its entirety.

Item 14. *Principal Accounting Fees and Services*

The following table presents fees for professional services rendered by Deloitte & Touche LLP, or Deloitte, our principal accountant, for the audit of our financial statements for the years ended December 31, 2006 and 2005, and the fees billed for other services rendered by Deloitte during the year ($ in millions):

Type of Fees	**2006**	**2005**
Audit Fees(a)	$ 2.5	$ 2.3
Audit-Related Fees	$	$
Tax Fees	$	$
All Other Fees	$	$
Total Fees	$ 2.5	$ 2.3

(a) Audit Fees are fees billed by Deloitte for professional services for the audit of our consolidated financial statements included in our annual report on Form 10-K and review of financial statements included in our quarterly reports on Form 10-Q, services that are normally provided by Deloitte in connection with statutory and regulatory filings or engagements or any other service performed by Deloitte to comply with generally accepted auditing standards and include comfort and consent letters in connection with Securities and Exchange Commission filings and financing transactions.

Audit Committee Pre-Approval Policy

The audit committee pre-approves all audit and permissible non-audit services provided by the independent auditors on a case-by-case basis. These services may include audit services, audit-related services, tax services and other services. The audit committee does not delegate its responsibilities to pre-approve services performed by the independent auditor to management or to an individual member of the audit committee. The audit committee may, however, from time to time delegate its authority to the audit committee Chairman, who reports on the independent auditor services approved by the Chairman at the next audit committee meeting.

Part IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) *Financial Statement Schedules.*

DCP MIDSTREAM PARTNERS, LP

SCHEDULE II CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Deductions/ Other ($ in millions)	Credit to Consolidated Statements of Operations	Balance at End of Period
December 31, 2006					
Allowance for doubtful accounts	$ 0.3	$ 0.3	$ (0.3)	$	$ 0.3
Environmental	0.1				0.1
Other(a)		0.3			0.3
	$ 0.4	$ 0.6	$ (0.3)	$	$ 0.7
December 31, 2005					
Allowance for doubtful accounts	$ 0.3	$ 0.1	$	$ (0.1)	$ 0.3
Environmental		0.2	(0.1)		0.1
Other(a)	1.3		(1.3)		
	$ 1.6	$ 0.3	$ (1.4)	$ (0.1)	$ 0.4
December 31, 2004					
Allowance for doubtful accounts	$ 0.3	$	$	$	$ 0.3
Environmental					
Other(a)	1.3				1.3
	$ 1.6	$	$	$	$ 1.6

(a) Principally consists of other contingency liabilities, which are included in other current liabilities.

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(b) *Exhibits.*

A list of exhibits required by Item 601 of Regulation S-K to be filed as part of this report:

Exhibit Number	Description
1.1**	Underwriting Agreement, dated December 1, 2005 among DCP Midstream, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, DCP Midstream GP, LLC, DCP Midstream Operating, LP and Lehman Brothers Inc. and Citigroup Global Markets Inc. as representatives of the several underwriters named therein.
3.1**	Amended and Restated Limited Partnership Agreement of DCP Midstream Partners, LP.
3.2**	First Amended and Restated Limited Partnership Agreement of DCP Midstream GP, LP.
3.3**	First Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC.
3.4***	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP.
10.1**	Omnibus Agreement, dated December 7, 2005, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP.
10.2**	DCP Midstream Partners, LP Long-Term Incentive Plan.
10.3**	Contribution, Conveyance and Assumption Agreement, dated December 7, 2005, among DCP Midstream Partners, LP, DCP Midstream Operating, LP, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, DCP Midstream Holding 1, LLC, DCP Midstream Holding, LLC, DCP Assets Holdings, LP, DCP Assets Holdings GP, LLC, Duke Energy Guadalupe Pipeline Holdings, Inc., Duke Energy NGL Services, LP, DCP LP Holdings, LP and DCP Black Lake Holdings, LLC.
10.4**	Credit Agreement, dated December 7, 2005, between DCP Midstream Operating, LP and Wachovia Bank, National Association, as administrative agent for the lenders named therein.
10.5*	Natural Gas Gathering Agreement, dated June 1, 1987, as amended, between DCP Midstream Assets Holding, LP, successor to the interest of Cornerstone Natural Gas Company and ConocoPhillips, successor to the interest of Phillips Petroleum Company.
10.6+	First Amendment to Omnibus Agreement, dated April 1, 2006, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP.
10.7++	Contribution Agreement, dated October 9, 2006, between DCP LP Holdings, LP and DCP Midstream Partners, LP.
10.8***	Second Amendment to Omnibus Agreement, dated November 1, 2006, among DCP Midstream, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, DCP Midstream GP, LLC, and DCP Midstream Operating, LP.
21.1	List of Subsidiaries of DCP Midstream Partners, LP.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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.
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.

* Incorporated by reference from DCP Midstream Partners, LP Amendment No. 2 to Registration Statement on Form S-1 filed with the Securities and Exchange Commission on November 18, 2005 (File No. 333-128378).

** Incorporated by reference from DCP Midstream Partners, LP Form 8-K filed with the Securities and Exchange Commission on December 12, 2005 (File No. 001-32678).

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Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

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SIGNATURES

Pursuant to the requirements of the 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, in the City of Denver, State of Colorado, on March 14, 2007.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP

its General Partner

By: DCP Midstream GP, LLC

its General Partner

By: /s/ Mark A. Borer

Name: Mark A. Borer
Title: President and Chief Executive Officer

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POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS that each person whose signature appears below constitutes and appoints each of Mark A. Borer and Thomas E. Long as his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or in his name, place, and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this annual report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Mark A. Borer Mark A. Borer	President, Chief Executive Officer and Director (Principal Executive Officer)	March 14, 2007
/s/ Thomas E. Long Thomas E. Long	Vice President and Chief Financial Officer (Principal Financial Officer)	March 14, 2007
/s/ Jim W. Mogg Jim W. Mogg	Chairman of the Board	March 14, 2007
/s/ William H. Easter III William H. Easter III	Director	March 14, 2007
/s/ Paul F. Ferguson, Jr. Paul F. Ferguson, Jr.	Director	March 14, 2007
/s/ John E. Lowe John E. Lowe	Director	March 14, 2007
/s/ Derrill Cody Derrill Cody	Director	March 14, 2007
/s/ Frank A. McPherson Frank A. McPherson	Director	March 14, 2007

/s/ Thomas C. Morris	Director	March 14, 2007
Thomas C. Morris		

EXHIBIT INDEX

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