DCP Midstream Partners, LP
Form 10-K
March 05, 2009

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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, 2008**
	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 *(State or other jurisdiction of incorporation or organization)*	**03-0567133** *(I.R.S. Employer Identification No.)*
370 17th Street, Suite 2775 **Denver, Colorado** *(Address of principal executive offices)*	**80202** *(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. o

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

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

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant on June 30, 2008, was approximately $582,555,000. 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, 2008.

As of February 23, 2009, there were outstanding 28,233,183 common limited partner units.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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GLOSSARY OF TERMS

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

Bbl	barrel
Bbls/d	barrels per day
BBtu/d	one billion Btus per day
Bcf/d	one billion cubic feet 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
MMBtu	one million Btus
MMBtu/d	one million Btus per day
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
MMscf	one million standard cubic feet
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 extent of changes in commodity prices, our ability to effectively 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;

- general economic, market and business conditions;

- 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 limit a portion of the adverse effects of potential changes in interest rates by entering into derivative financial instruments, and the credit ratings for our debt obligations;

- 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 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, increased delivery of liquefied natural gas to the United States, alternative energy sources, technological advances and changes in competition; and

the amount of collateral we may be required to post from time to time in our transactions.

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 in August 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We completed our initial public offering on December 7, 2005. We are currently engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas, producing, transporting, storing and selling propane in wholesale markets and transporting and selling NGLs and condensate. Supported by our relationship with DCP Midstream, LLC and its parents, Spectra Energy Corp, or Spectra Energy, and ConocoPhillips, we have a management team dedicated to executing our growth strategy by acquiring and constructing additional assets.

Our operations are organized into three business segments, Natural Gas Services, Wholesale Propane Logistics and NGL Logistics. A map representing the location of the assets that comprise our segments is set forth below. Additional maps detailing the individual assets can be found on our website at *www.dcppartners.com*.

Our Natural Gas Services segment includes:

Our Northern 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 transports and sells NGLs and condensate. This system consists of the following:

the Minden processing plant and gathering system, which includes a 115 MMcf/d cryogenic natural gas processing plant supplied by approximately 725 miles of natural gas gathering pipelines, connected to approximately 460 receipt points, with throughput and processing capacity of approximately 115 MMcf/d;

the Ada processing plant and gathering system, which includes a 45 MMcf/d 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 Southern Oklahoma, or Lindsay, gathering system, which was acquired in May 2007, consists of approximately 225 miles of pipeline, with throughput capacity of approximately 35 MMcf/d.

Our equity interests that were acquired in July 2007 from DCP Midstream, LLC, consist of the following:

our 40% interest in Discovery Producer Services LLC, or Discovery, which operates a 600 MMcf/d cryogenic natural gas processing plant, a natural gas liquids fractionator plant, an approximately 280-mile natural gas pipeline with approximate throughput capacity of 600 MMcf/d that transports gas from the Gulf of Mexico to its processing plant, and several onshore laterals expanding its presence in the Gulf; and

our 25% interest in DCP East Texas Holdings, LLC, or East Texas, which operates a 780 MMcf/d natural gas processing complex, a natural gas liquids fractionator and an approximately 900-mile gathering system with approximate throughput capacity of 780 MMcf/d, as well as third party gathering systems, and delivers residue gas to interstate and intrastate pipelines.

Our Colorado and Wyoming gathering, processing and compression assets were acquired in August 2007 from DCP Midstream, LLC, and consist of the following:

our 70% operating interest in the approximately 30-mile Collbran Valley Gas Gathering system, or Collbran system, has assets in the Piceance Basin that gather and process natural gas from over 20,000 dedicated acres in western Colorado, and a processing facility with a capacity of 120 MMcf/d; and

The Powder River Basin assets, which include the approximately 1,320-mile Douglas gas gathering system, or Douglas system, with throughput capacity of approximately 60 MMcf/d and covers more than 4,000 square miles in northeastern Wyoming, and Millis terminal, and associated NGL pipelines in southwestern Wyoming.

Our Michigan gathering and treating assets were acquired in October 2008 from Michigan Pipeline & Processing, LLC, or MPP. These assets consist of five natural gas treating plants and an approximately 155-mile gas gathering pipeline system with throughput capacity of 330 MMcf/d; an approximately 55-mile residue gas pipeline; a 75% interest in Jackson Pipeline Company, a partnership owning an approximately 25-mile residue pipeline, or Jackson Pipeline; and a 44% interest in the Litchfield pipeline, a 30-mile pipeline whereby we lease our undivided interest to ANR Pipeline Company through the use of a direct financing lease expiring in 2031.

Our Wholesale Propane Logistics segment acquired in November 2006 from DCP Midstream, LLC includes:

six owned rail terminals located in the Midwest and northeastern United States, one of which was idled in 2007 to consolidate our operations, with aggregate storage capacity of 25 MBbls;

one leased marine terminal located in Providence, Rhode Island, with storage capacity of 410 MBbls;

- one pipeline terminal located in Midland, Pennsylvania with storage capacity of 56 MBbls; and
- access to several open access pipeline terminals.

Our NGL Logistics segment includes:

- our Seabreeze pipeline, an approximately 68-mile intrastate NGL pipeline located in Texas with throughput capacity of 33 MBbls/d;

our Wilbreeze pipeline, the construction of which was completed in December 2006, an approximately 39-mile intrastate NGL pipeline located 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.

We have no revenue or segment profit or loss attributable to international activities.

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 have sustained company profitability and a strong balance sheet. In addition, we would focus on profitable growth, thereby increasing 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 maintaining existing volumes and adding volumes to enhance utilization, improving operating efficiencies and capturing marketing opportunities when available. Our natural gas and NGL pipelines have excess capacity, which allows us to connect new supplies of natural gas and NGLs at minimal incremental cost. Our wholesale propane logistics business has diversified supply options that allow us to capture lower cost supply to lock in our margin, while providing reliable supplies to our customers.

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 several of our gas gathering systems to attach increased volumes of natural gas produced in the areas of our operations. We also believe that we can continue to expand our wholesale propane logistics business via the construction of new propane terminals.

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. We believe there will continue to be acquisition opportunities as energy companies continue to divest their midstream assets. 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.

The execution of our business strategies and our level of growth is dependent upon the availability and cost of capital, as well as the availability of growth opportunities. The recent turmoil in the capital markets has resulted in significantly higher costs of public debt and equity funds.

Our Competitive Strengths

We believe that we are well positioned to execute our business strategies and achieve our primary business objective of increasing our cash distribution per unit 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, should continue to 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. This relationship 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 the implementation of our strategies. Additionally, we believe DCP Midstream, LLC, which operates many of our assets on our behalf, 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, efficient and environmentally responsible operation of our facilities.

Strategically located assets. Our assets are strategically located in areas that hold potential for expanding each of our business segments volume throughput and cash flow generation. Our Natural Gas Services segment has a strategic presence in several active natural gas producing areas including western Colorado, northern Louisiana, Michigan, southern Oklahoma, eastern Texas, northeastern Wyoming and the Gulf of Mexico. These natural gas gathering systems provide a variety of services to our customers including natural gas gathering, compression, treating, processing, fractionation and transportation services. The strategic location of our assets, coupled with their geographic diversity, presents us continuing opportunities to provide competitive natural gas services to our customers and opportunities to attract new natural gas production. Our NGL Logistics segment has strategically located NGL transportation pipelines in northern Louisiana, eastern Texas and southern Texas, all of which are major NGL producing regions. Our NGL pipelines connect to various natural gas processing plants in the region and transport the NGLs to large fractionation facilities, a petrochemical plant or an underground NGL storage facility along the Gulf Coast. Our Wholesale Propane Logistics Segment has terminals in the Northeastern and upper Midwestern states that are strategically located to receive and deliver propane to one of the largest demand areas for propane in the United States.

Stable cash flows. Our operations consist of a favorable mix of fee-based and commodity-based services, which together with our derivative activities, generate relatively stable cash flows. While certain of our gathering and processing contracts subject us to commodity price risk, we have mitigated a significant portion of our currently anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with fixed price natural gas and crude oil swaps. For additional information regarding our derivative activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk Commodity Cash Flow Protection Activities.

Integrated package of midstream services. We provide an integrated package of services to natural gas producers, including gathering, compressing, treating, processing, transporting and selling natural gas, as well as transporting and selling NGLs. 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 services that 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 diversity of supply sources and 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 supplies 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 strengths is our relationship with DCP Midstream, LLC and its parents, Spectra Energy and ConocoPhillips. DCP Midstream, LLC intends to use us as an important growth vehicle to pursue the acquisition, expansion, and existing and organic construction of midstream natural gas, NGL and other complementary energy businesses and assets. In November 2006, we acquired our wholesale propane logistics business, in July 2007, we acquired our interest in Discovery and East Texas, and in August 2007, we acquired our Collbran and Douglas systems associated with Momentum Energy Group, Inc., or MEG, from DCP Midstream, LLC. We expect to have future opportunities to make additional acquisitions directly from DCP

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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 approximately 1% general partner interest in us, all of our incentive distribution rights and a 29% 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 the operation of many of our assets, as well as certain reimbursement and indemnification matters.

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, transporting and selling of natural gas, and the production, transporting and selling of NGLs.

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 from the natural gas that can have higher values as NGLs. NGLs are typically recovered by cooling the natural gas until the NGLs become separated through condensation. Cryogenic recovery methods are processes where this is accomplished at temperatures lower than minus 150°F. These methods provide higher NGL recovery yields. After being extracted from natural gas, the 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, which must also be removed to meet the quality standards for long-haul pipeline transportation. 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. 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. 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.

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 and the delivery of propane to retail distributors.

Production of Propane

Propane is extracted from the natural gas stream at processing plants, separated from 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 in the mid-continent, along the Texas and Louisiana Gulf Coast or in foreign locations, particularly Canada, the North Sea, East Africa and the Middle East. There are limited processing plants and fractionation facilities in the northeastern United States, and propane production is limited.

Transportation

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.

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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 propane at the rack and transport it to the retailer at its location. Each truck has transport capacity of generally between 9,500 and 12,500 gallons of propane.

Natural Gas Services Segment

General

Our Natural Gas Services segment consists of a geographically diverse complement of assets and ownership interests that provide a varying array of wellhead to market services for our producer customers. These services include gathering, compressing, treating, processing, fractionating and transporting natural gas; however, we do not offer all services in every location. These assets are positioned in areas with active drilling programs and opportunities for both organic growth and readily integrated acquisitions. We operate in seven states in the continental United States: Arkansas, Colorado, Louisiana, Michigan, Oklahoma, Texas and Wyoming. The assets in these states include our Northern Louisiana system, our Southern Oklahoma system, our equity interests in Discovery and East Texas, our 70% operating interest in the Collbran system, our Douglas system, and our Michigan gathering and treating assets. The Southern Oklahoma and East Texas assets provide operating synergies and opportunities for growth in conjunction with DCP Midstream. This geographic diversity helps to mitigate our natural gas supply risk in that we are not tied to one natural gas producing area. We believe our current geographic mix of assets will be an important factor for maintaining overall volumes and cash flow for this segment.

Our Natural Gas Services segment consists of approximately 4,500 miles of pipe, five processing plants, a treating plant, two NGL fractionation facilities and over 120,000 horsepower of compression capability. The processing plants that service our natural gas gathering systems include one cryogenic facility with approximately 115 MMcf/d of processing capacity, two refrigeration style facilities with approximately 165 MMcf/d of processing capacity and two cryogenic facilities owned via equity interests with our proportionate share at approximately 435 MMcf/d of processing capacity. Further, our Minden and Discovery processing facilities both have ethane rejection capabilities that serve to optimize value of the gas stream. The combined NGL production from our processing facilities is in excess of 20,000 barrels per day and is delivered and sold into various NGL takeaway pipelines or trucked out.

The volume throughput on our assets is in excess of 830 MMcf/d from over 3,600 individual receipt points and originates from a diversified mix of natural gas producing companies. Our Southern Oklahoma, East Texas, Northern Louisiana, Discovery and Collbran systems each have significant customer acreage dedications that will continue to provide opportunities for growth as those customers execute their drilling plans over time. Our gathering systems also attract new natural gas volumes through numerous smaller acreage dedications and also by contracting with undedicated producers who are operating in or around our gathering footprint.

We have primarily a mix of percent-of-proceeds and fee-based contracts with our producing customers in our Natural Gas Services segment. Contracts at Minden, Southern Oklahoma, Douglas, Discovery and East Texas have a large component of percent-of-proceeds contracts due to the processing value of the gas streams at each of these systems. In addition, Discovery may also generate a portion of its earnings through keep-

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whole contracts. The Pelico, Ada, Minden, Collbran and Michigan systems are predominantly supported by fee-based contracts. This diverse contract mix is a result of contracting patterns that are largely a result of the competitive landscape in each particular geographic area.

In total, our natural gas gathering systems have the ability to deliver gas into over 20 downstream transportation pipelines and markets. Many of our outlets transport gas to premium markets in the eastern United States, further enhancing the competitiveness of our commercial efforts in and around our natural gas gathering systems.

Gathering Systems, Processing Plants and Transportation Systems

Following is operating data for our systems:

System	Approximate Gas Gathering and Transmission System (Miles)	Partnership Operated Plants	Plants Operated by Others	Fractionator Operated by Others	Approximate Net Plant Capacity (MMcf/d)	2008 Operating Data Natural Gas Throughput (MMcf/d)(a)	2008 Operating Data NGL Production (Bbls/d)(a)
Minden	725	1			115	83	4,619
Ada	130	1			45	62	165
Pelico	600					171	
Southern Oklahoma (Lindsay)	225					18	2,203
Collbran	30	1			120	90	486
Douglas	1,320					16	1,025
Michigan	265					75	
Discovery	280		1	1	240(b)	170(b)	4,703(b)
East Texas	900		1	1	195(b)	153(b)	7,458(b)
Total	4,475	3	2	2	715	838	20,659

(a) Represents total volumes for 2008 divided by 366 days.

(b) For Discovery and East Texas, includes our 40% and 25% proportionate share, respectively, of the approximate net plant capacity, natural gas throughput and NGL production.

The Northern Louisiana natural gas gathering system includes the Minden, Ada and Pelico systems, which gather natural gas from producers at approximately 670 receipt points and deliver it for processing to the processing plants. The Minden gathering system also delivers NGLs produced at the Minden processing plant to our 45% owned Black Lake pipeline. There are 26 compressor stations located within the system, comprised of 60 units with an aggregate of approximately 70,000 horsepower. Through our Northern Louisiana system, we offer producers and customers wellhead-to-market services. The Northern Louisiana system has numerous market outlets for the natural gas we gather, including several intrastate and interstate pipelines, major industrial end-users and major power plants. The system is strategically located to facilitate the transportation of natural gas from Texas and northern Louisiana to pipeline connections linking to markets in the eastern and northeastern areas of the United States.

The Minden processing plant is a cryogenic natural gas processing and treating plant located in Webster Parish, Louisiana. 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 the majority of the ethane 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 certain 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. The defined return on the initial investment for this ethane recovery upgrade was reached in 2007.

The Ada gathering system is located in Bienville and Webster parishes in Louisiana and the Ada processing plant is a refrigeration natural gas processing plant located in Bienville Parish, Louisiana. This low pressure gathering system compresses and processes natural gas for our producing customers and delivers residue gas into our Pelico intrastate system. We then sell the NGLs to third-parties who truck them from the plant tailgate.

The Pelico system is an intrastate natural gas gathering and transportation pipeline that 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 Texas through its interconnect with other pipelines that transport natural gas from Texas into western Louisiana.

The Southern Oklahoma system consists of 9,500 horsepower of compression, and approximately 350 receipt points, and is located in the Golden Trend area of McClain, Garvin and Grady counties in southern Oklahoma. The system was acquired from Anadarko Petroleum Corporation in May 2007 and is adjacent to assets owned by DCP Midstream, LLC. Currently, natural gas gathered by the system is delivered to the Oneok Maysville plant for processing; however, we will have the ability in 2009 to process the gas at a DCP Midstream, LLC processing plant to enhance our processing economics. The current Maysville connection provides marketing flexibility to multiple pipelines and access to local liquid markets using Oneok s fractionation capabilities.

The Collbran system has assets in the southern Piceance Basin that gather natural gas at high pressure from over 20,000 dedicated acres in western Colorado, and a refrigeration natural gas processing plant with a current capacity of 120 MMcf/d. Our 70% operating interest in the Collbran system was acquired from DCP Midstream, LLC in August 2007 following its acquisition of MEG. The remaining interests in the joint venture are held by Occidental Petroleum Corporation (25%) and Delta Petroleum Corporation (5%), who are also producers on the system. The processing plant was expanded in 2008 to an operating capacity to 120 MMcf/d to accommodate expected increases in volumes. The Collbran system is currently undergoing a further expansion, which is scheduled to be completed in the third quarter of 2009, consisting of an additional 24-inch pipeline loop and compression at the Anderson Gulch site. The expansion, expected to be completed in 2009, would increase the pipeline capacity to over 200 MMcf/d and enable gas deliveries to the Meeker Plant through a downstream connection with Enterprise Products Partners LP, which is also expanding its system feeding its plant. The Collbran system is designed to ultimately have throughput capacity of over 600 MMcf/d depending on future production growth.

The Douglas system has natural gas gathering pipelines that cover more than 4,000 square miles in Wyoming with over 1,300 miles of pipe. The system gathers primarily rich casing-head gas from oil wells at low pressure from approximately 650 receipt points and delivers the gas to a third party for processing under a fee agreement. The Douglas system has approximately 16,000 horsepower of compression to maintain our low pressure gathering service. The Douglas system was acquired from DCP Midstream, LLC in August 2007 following its acquisition of MEG.

We acquired MPP on October 1, 2008. These assets consist of five natural gas treating plants and an approximately 155-mile gas gathering pipeline system with throughput capacity of 330 MMcf/d; an approximately 55-mile residue gas pipeline; a 75% interest in Jackson Pipeline Company, a partnership owning an approximately 25-mile residue pipeline; and a 44% interest in the Litchfield pipeline, a 30-mile pipeline whereby we lease our undivided interest to ANR Pipeline Company through the use of a direct financing lease expiring in 2031.

We have a 40% equity interest in Discovery and the remaining 60% is owned by Williams Partners, L.P. Discovery owns (1) a natural gas gathering and transportation pipeline system located primarily off the coast of Louisiana in the Gulf of Mexico, with six delivery points connected to major interstate and intrastate pipeline systems; (2) a cryogenic natural gas processing plant in Larose, Louisiana; (3) a fractionator in Paradis, Louisiana and (4) an NGL pipeline connecting the gas processing plant to the fractionator. The Discovery system, operated by the Williams Companies, offers a full range of wellhead-to-market services to both onshore and offshore natural gas producers. The assets are primarily located in the eastern Gulf of Mexico and Lafourche Parish, Louisiana. The Discovery system is able to reject the majority of the ethane when justified by market economics.

Discovery is managed by a two-member management committee, consisting of one representative from each owner. The members of the management committee have voting power corresponding to their respective ownership interests in Discovery. All actions and decisions relating to Discovery require the unanimous approval of the owners except for a few limited situations. Discovery must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval based on the ownership percentage represented, will determine the amount of the distributions. In addition, the owners are required to offer to Discovery all opportunities to construct pipeline laterals within an area of interest.

Additionally, Discovery has signed definitive agreements with Chevron Corporation, Total E&P USA, Inc., and StatoilHydro ASA to construct an approximate 34-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. The Tahiti pipeline lateral expansion has a design capacity of approximately 200 MMcf/d. Chevron expects first production to commence in the third quarter of 2009. In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC made capital contributions to us as reimbursement for remaining costs for the Tahiti pipeline lateral expansion, which were substantially completed in 2008.

We own a 25% interest in East Texas (the remaining 75% is owned by DCP Midstream, LLC), which gathers, transports, treats, compresses and processes natural gas and NGLs. The East Texas facility may also fractionate NGL production, which can be marketed at nearby petrochemical facilities. The operations, located near Carthage, Texas, include a natural gas processing complex that is connected to its gathering system, as well as third party gathering systems. The complex includes the Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub acts as a key exchange point for the purchase and sale of residue gas in the eastern Texas region. The East Texas system consists of approximately 900 miles of pipe, processing capacity of 780 MMcf/d, fractionation capacity of 11,000 Bbls/d, over 25,000 horsepower of compression and serves over 1,500 receipt points in and around its geographic footprint.

East Texas is managed by a four-member management committee, consisting of two representatives from each owner. The members of the management committee have voting power corresponding to their respective ownership interests in East Texas. Most significant actions relating to East Texas require the unanimous approval of both owners. East Texas must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval, will determine the amount of the distributions.

Natural Gas and NGL Markets

The Northern 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 in northern Louisiana 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 Northern Louisiana system is also connected to eight major industrial end-users and makes deliveries to three power plants.

The NGLs extracted from the natural gas at the Minden processing plant are delivered to our 45%-owned Black Lake pipeline through our wholly-owned approximately 9-mile Minden NGL pipeline. The Black Lake pipeline delivers NGLs to Mt. Belvieu. The NGLs extracted from natural gas at the Ada processing plant are sold at market index prices to affiliates and are delivered to third parties trucks at the tailgate of the plant.

The Southern Oklahoma system has access through the Maysville processing plant to deliver gas into mid-continent transmission pipelines such as Oneok Gas Transportation and Southern Star Central Gas Pipelines, among others. When the Southern Oklahoma system delivers into the DCP Midstream, LLC owned processing plant(s) in the second quarter of 2009, a similar mix of mid-continent pipelines and markets will be available to our customers. NGLs produced from this system are delivered to Oneok Gas Transportation.

The Collbran system in western Colorado delivers gas into the TransColorado Gas Transmission interstate pipeline and to the Rocky Mountain Natural Gas LDC. The Douglas system in the Powder River basin in northeastern Wyoming delivers to the Kinder Morgan Interstate Gas Transmission interstate pipeline. The NGLs from the Collbran system are trucked off site by third party purchasers, while NGLs on the Douglas system are transported on the ConocoPhillips owned Powder River Pipeline.

The Michigan Antrim gas gathering and treating system delivers Antrim Shale gas to the South Chester Treating Complex. Antrim Shale natural gas requires treating in order to meet downstream gas pipeline quality specifications. The treated gas is transported to MichCon Gathering system from the tailgate of the plant. The Bay Area pipeline delivers fuel gas to a third party power plant owned by Consumers Energy. The Jackson Pipeline is operated by Consumers Energy and connects several intrastate pipelines with the Eaton Rapids gas storage facility. The Litchfield pipeline is operated by ANR Pipeline Company and facilitates receipts or deliveries between ANR Pipeline Company and the Eaton Rapids storage facility. All Michigan assets were acquired from MPP on October 1, 2008.

The Discovery assets have access to downstream pipelines and markets including Texas Eastern Transmission Company, Bridgeline, Gulf South Pipeline Company, Transcontinental Gas Pipeline Company, Columbia Gulf Transmission and Tennessee Gas Pipeline Company, among others. The NGLs are fractionated at the Paradis fractionation facilities and delivered downstream to third-party purchasers. The third party purchasers of the fractionated NGLs consist of a mix of local petrochemical facilities and wholesale distribution companies for the ethane and propane components, while the butanes and natural gasoline are delivered and sold to pipelines that transport product to the storage and distribution center near Napoleonville, Louisiana or other similar product hub.

The East Texas system delivers gas primarily to the Carthage Hub which delivers residue gas to ten different interstate and intrastate pipelines including Centerpoint Energy Gas Transmission, Texas Gas Transmission, Tennessee Gas Pipeline Company, Natural Gas Pipeline Company of America, Gulf South Pipeline Company, Enterprise and others. Certain of the lighter NGLs, consisting of ethane and propane, are fractionated at the East Texas facility and sold to regional petrochemical purchasers. The remaining NGLs, including butanes and natural gasoline, are purchased by DCP Midstream, LLC and shipped on the Panola NGL pipeline to Mont Belvieu for fractionation and sale.

Customers and Contracts

The primary suppliers of natural gas to our Natural Gas Services segment are a broad cross-section of the natural gas producing community. We actively seek new producing customers of natural gas on all of our systems 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 directly received or released from other gathering systems.

We had no third-party customers in our Natural Gas Services segment that accounted for greater than 10% of our revenues.

Our contracts with our producing customers in our Natural Gas Services segment are primarily a mix of commodity sensitive percent-of-proceeds contracts and non-commodity sensitive fee-based contracts. Generally, the initial term of these purchase agreements is for three to five years or, in some cases, the life of the lease. The largest percentage of volume at Minden, Southern Oklahoma, Douglas and East Texas are processed under percent-of-proceeds contracts. Discovery has percent-of-proceeds contracts and fee-based contracts, as well as some keep-whole contracts. The majority of the contracts for our Pelico, Ada, Collbran and Michigan systems are fee-based agreements. Our gross margin generated from percent-of-proceeds contracts is directly correlated to the price of natural gas, NGLs and condensate.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally correlated to the price of crude oil, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close correlation. Changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing operations through 2013.

Discovery s wholly owned subsidiary, Discovery Gas Transmission, owns the mainline and the Federal Energy Regulatory Commission, or FERC-regulated laterals, which generate revenues through a tariff on file with the FERC for several types of service: traditional firm transportation service with reservation fees (although no current shippers have elected this service); firm transportation service on a commodity basis with reserve dedication; and interruptible transportation service. In addition, for any of these general services, Discovery Gas Transmission has the authority to negotiate a specific rate arrangement with an individual shipper and has several of these arrangements currently in effect.

Competition

Competition in our Natural Gas Services segment is highly competitive in our markets and includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or natural gas liquids. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter in length of term and therefore must be renegotiated on a more frequent basis.

Wholesale Propane Logistics Segment

General

We operate a wholesale propane logistics business in the states of Connecticut, Maine, Massachusetts, New Hampshire, New York, Ohio, Pennsylvania, Rhode Island and Vermont.

Due to our multiple propane supply sources, annual and 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, low cost deliveries and greater volumes of propane during periods of tight supply such as the winter months. We believe these factors generally allow us to maintain favorable relationships with our customers.

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 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. Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may continue to periodically recognize non-cash lower of cost or market inventory adjustments. In addition, we may, on occasion, use financial derivatives to manage the value of our propane inventories.

Pipeline deliveries to the northeast market 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 constructed a propane pipeline terminal located in Midland, Pennsylvania that became operational in May 2007, and we are actively seeking new terminals through acquisition or construction to expand our distribution capabilities, subject to the availability of capital.

Our Terminals

Our operations include six propane rail terminals with aggregate storage capacity of 25 MBbls, one of which was idled in 2007 to consolidate our operations, one propane marine terminal with storage capacity of 410 MBbls, one propane pipeline terminal with storage capacity of 56 MBbls and access to several open access pipeline terminals. We own our rail terminals and lease the land on which the terminals are situated under long-term leases, except for the York terminal where we own the land. The marine terminal is leased on a long-term lease agreement. Each of our rail terminals consist of two to three propane tanks with capacity of between 120,000 and 270,000 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.

We are also actively seeking to expand and favorably position our wholesale propane distribution business into the upper Midwest and Mid-Atlantic states, and have constructed a propane pipeline terminal in western Pennsylvania that became operational in May 2007.

Propane Supply

Our wholesale propane business has a strategic network of supply arrangements under annual and multi-year agreements under index-based pricing. The remaining supply is purchased on annual or month-to-month terms to match our anticipated sale requirements. During 2008, our primary suppliers of propane included a subsidiary of DCP Midstream, LLC, Aux Sable Liquid Products LP and Spectra Energy. During 2007, our primary suppliers of propane included Shell International Trading and Shipping Company, Aux Sable Liquid Products LP and a subsidiary of DCP Midstream, LLC.

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. We also purchase propane supply from natural gas fractionation plants and crude oil refineries located in the Texas and Louisiana Gulf Coast. 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 have historically contracted under annual agreements for delivered shipments of propane. In May 2008, we entered into a long term contract with Spectra Energy that offers both product and shipping capabilities. The port where the marine terminal facility is located has been expanded, and we can now receive propane supply from larger propane tankers.

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Customers and Contracts

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 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.

We had no third-party customers in our Wholesale Propane Logistics segment that accounted for greater than 10% of our revenues.

Competition

The wholesale propane business is highly competitive in the upper midwest and northeastern regions of the United States. Our wholesale propane business competitors include major integrated oil and gas and energy companies, and interstate and intrastate pipelines.

NGL Logistics Segment

General

We operate our NGL Logistics business in the states of Louisiana and Texas.

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 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 2008 average throughput was approximately 31 MBbls/d.

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 recover NGLs from natural gas because of the higher value of natural gas compared to the value of NGLs. 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. The Seabreeze pipeline has capacity of 33 MBbls/d and for 2008 average throughput on the pipeline was approximately 17 MBbls/d. The Seabreeze pipeline was put into service in 2002 to deliver NGLs to a large processing plant with capacity of approximately 340 MMcf/d located in Matagorda County, and a NGL pipeline. The Seabreeze pipeline also delivered to a second plant, which was closed during 2008. The

Seabreeze pipeline is the sole NGL pipeline for one processing plant and is the only delivery point for two NGL pipelines. One 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. In total seven processing plants produce NGLs that flow into the Seabreeze pipeline from processed natural gas produced in southern Texas and offshore in the Gulf of Mexico. The Seabreeze pipeline delivers the NGLs it receives from these sources to a fractionator and a storage facility. We completed construction of our Wilbreeze pipeline in December 2006. Current capacity of the Wilbreeze pipeline is 11 MBbls/d and average throughput on the pipeline was approximately 6 MBbls/d for 2008.

Black Lake Pipeline. The Black Lake pipeline has capacity of 40 MBbls/d and for 2008, average throughput on the Black Lake pipeline at our 45% interest was approximately 8 MBbls/d. 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 NGLs 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, and also receives NGLs from XTO Energy Inc. s Cotton Valley processing plant. In addition, the Black Lake pipeline receives NGLs from a natural gas processing plant located in southeastern Texas.

There are currently five significant active shippers on the pipeline, with DCP Midstream, LLC historically being the largest, representing approximately 47% of total throughput in 2008. The Black Lake pipeline generates revenues through a FERC-regulated tariff, and the average rate per barrel was $1.00 in 2008, $0.95 in 2007 and $0.94 in 2006.

Black Lake is a partnership that is operated by and 50% owned by BP PLC. 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. This project was completed and cash distributions resumed during 2008.

Customers and Contracts

The Wilbreeze pipeline is supported by an NGL product dedication agreement with DCP Midstream, LLC.

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 long-term transportation agreement. 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 an NGL purchase agreement with Williams. Under this agreement, Williams has dedicated all of their respective NGL production from this processing plant to DCP Midstream, LLC. DCP Midstream, LLC has a sales agreement with Formosa. Additionally, DCP Midstream, LLC has a transportation agreement with TEPPCO Partners, L.P. that covers all of the NGL volumes transported on TEPPCO Partners, L.P. s South Dean NGL pipeline for delivery to the Seabreeze pipeline.

We had no third-party customers in our NGL Logistics segment that accounted for greater than 10% of our revenues.

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, 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, including NGLs and condensate, 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, as amended, 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 in high-consequence areas within 10 years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that requires 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 $2.0 million between 2009 and 2013 to implement integrity management program testing along certain segments of our natural gas transmission 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 agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing. We anticipate repairs of approximately $0.8 million on the pipeline, which will be funded directly from Black Lake. We will not make contributions to Black Lake to cover these expenses.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards. 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 transmission and regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of 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 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.

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

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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.

FERC Regulation of Operations

FERC 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.

Interstate Natural Gas Pipeline Regulation

The Discovery 105-mile mainline, approximately 60 miles of laterals and its market expansion project are subject to regulation by FERC, under the Natural Gas Act of 1938, or NGA. Natural gas companies may not charge rates that have been determined not to be just and reasonable. In addition, the FERC s authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- terms and conditions of services and service contracts with customers;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates; and
- various other matters.

Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of service including recovery of and a return on the pipeline s actual prudent historical cost investment. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. The maximum applicable recourse rates and terms and conditions for service are set forth in each pipeline s FERC approved tariff. Rate design and the allocation of costs also can impact a pipeline s profitability. FERC-regulated natural gas pipelines are permitted to discount their firm and interruptible rates without further FERC authorization down to the variable cost of performing service, provided they do not unduly discriminate.

Tariff changes can only be implemented upon approval by the FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with the FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If the FERC determines that a proposed change is just and reasonable as required by the NGA, the FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if the FERC determines that a proposed change may not be just and reasonable as required by the NGA, then the FERC may suspend such change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by the FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, the FERC may, on its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If the FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

In November 2003, the FERC issued Order 2004 governing the Standards of Conduct for Transmission Providers (including natural gas interstate pipelines). These standards provide that interstate pipeline employees engaged in natural gas transmission system operations must function independently from any employees of their energy affiliates and marketing affiliates and that an interstate pipeline must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and cannot operate its transmission system to benefit preferentially, an energy or marketing affiliate. In addition, Order 2004 restricts access to natural gas transmission customer data by marketing and other energy affiliates and provides certain conditions on service provided by interstate pipelines to their gas marketing and energy affiliates. In November 2006, the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit, vacated Order 2004 as that order applies to interstate natural gas pipelines and remanded that proceeding to the FERC for further action.

On January 9, 2007, the FERC issued Order 690 in response to the D.C. Circuit s decision. In its Order, the Commission issued new interim standards of conduct pending the outcome of a new rulemaking proceeding. The interim standards only govern the relationship between an interstate pipeline and its marketing affiliates as opposed to its energy affiliates, the latter being a much broader category as originally set forth in Order 2004. As a result, the Commission effectively repromulgated on a temporary basis the Standards of Conduct first issued in Order 497 in 1992, while it considers its course of action to address the court s decision on a more permanent basis.

On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking or 2007 NOPR in Docket No. RM07-1 wherein it proposes to make permanent its interim standards of conduct issued in Order 690. The Commission also sought comment as to whether it should make comparable changes to the electric industry standards of conduct that were not affected by either the November 2006 decision by the D.C. Circuit, or by Order 690, as well as comments regarding certain other electric-related exceptions to Order 2004. We continue to closely monitor these proceedings and administer our compliance programs accordingly.

On March 21, 2008, FERC issued an NOPR to revise the Standards of Conduct to make them clearer and to refocus the rules on the areas where there is the greatest potential for affiliate abuse, or 2008 NOPR. The 2008 NOPR replaces the 2007 NOPR. The 2008 NOPR applies the Standards of Conduct to any interstate natural gas pipeline that conducts transportation transactions with an affiliate that engages in marketing functions. The definition of marketing function exempts sales from gathering and processing facilities.

On October 16, 2008, FERC issued Order No. 717 providing a final rule on the FERC Standards of Conduct that conforms to the U.S. Court of Appeals Decision. The final rule applies the Standards of Conduct to interstate natural gas pipelines that conduct transportation transactions with an affiliate that engages in marketing functions. Under the final rule, interstate pipeline transmission information is restricted from being disclosed to the affiliate s marketing function employees. The definition of marketing function employees is limited to those employees engaged on a day-to-day basis in the sale for resale of natural gas in interstate commerce. The FERC Standards of Conduct do not apply to Discovery under the final rule.

The Outer Continental Shelf Lands Act, or OCSLA, requires that all pipelines operating on or across the outer continental shelf, or OCS, provide open access, non-discriminatory transportation service. In an effort to heighten its oversight of transportation on the OCS, the FERC attempted to promulgate reporting requirements with respect to OCS transportation, but the regulations were struck down as ultra vires by a federal district court, which decision was affirmed by the D.C. Circuit in October 2003. The FERC withdrew those regulations in March 2004. Subsequently, in

April 2004, the Minerals Management Service, or MMS, initiated an inquiry into whether it should amend its regulations to assure that pipelines provide open and non-discriminatory access over OCS pipeline facilities. In April 2007, the MMS issued a notice of proposed rulemaking that would establish a process for a shipper transporting oil or gas production from OCS leases to follow if it believes it has been denied open and nondiscriminatory access to OCS pipelines. However, the proposed rule makes clear that the MMS will defer to FERC with respect to pipelines subject to FERC s NGA and Interstate Commerce Act jurisdiction, stating that the MMS would not consider complaints regarding a FERC pipeline that, for example, originates from a lease on the OCS and then transports production onshore to an adjacent state. The MMS has also proposed a regulation providing for civil penalties of up to $10,000 per day for violations of the OCSLA s open and nondiscriminatory access requirements. On June 18, 2008, the MMS issued a final rule regarding open and nondiscriminatory access to pipelines on the OCS that is generally consistent with the NOPR. The final rule did institute a time limit of two years from the time of the denial of open access for initiating a formal complaint. The final rule is effective August 18, 2008. We do not expect that the final rule will affect our OCS operations.

On July 19, 2007, FERC issued a proposed policy statement regarding the appropriate composition of proxy groups for purposes of determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. FERC proposed to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that the analysis be limited to actual publicly traded partnership distributions capped at the level of the pipeline s earnings and that evidence be provided in the form of a multiyear analysis of past earnings demonstrating a publicly traded partnership s ability to provide stable earnings over time. On November 15, 2007, the FERC requested additional comments regarding the method to be used for creating growth forecasts for publicly traded partnerships, and FERC held a technical conference on this issue in January 2008. On April 17, 2008, FERC issued a final policy statement regarding the appropriate composition of proxy groups. FERC concluded, among other things, that MLPs should be included in the Return on Equity or ROE proxy group for both oil and gas pipelines. FERC established a paper hearing for establishing the ROE for cases that were pending before FERC. The policy statement could result in the establishment of a higher ROE in future rate proceedings but the full effect is uncertain until the policy is applied.

On September 20, 2007, FERC issued a Notice of Inquiry regarding Fuel Retention Practices of Natural Gas Pipelines (Fuel NOI). The Fuel NOI inquires whether the current policy which allows natural gas pipelines to choose between two options for recovering the costs of fuel and lost and unaccounted for (LAUF) gas should be changed in favor of a uniform method. Comments have been filed in response to the Fuel NOI. On November 20, 2008, FERC terminated this proceeding and declined making any changes to the fuel retention practices of natural gas pipelines.

On September 20, 2007, FERC issued a Notice of Proposed Rulemaking regarding Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines (Reporting NOPR). The Reporting NOPR proposed to require pipelines to (i) provide additional information regarding their sources of revenue and amounts included in rate base; (ii) identify costs related to affiliate transactions; and (iii) provide additional information regarding incremental facilities, and discounted and negotiated rates. According to FERC, the changes would assist pipeline customers and other third parties in analyzing a pipeline s actual return as compared with its approved rate of return based on publicly filed data. On March 21, 2008, FERC issued Order No. 710 implementing revisions to the forms, statements and reporting requirements of natural gas pipelines. The order is effective on January 1, 2008 and impacts the 2008 FERC Form 2 and subsequent Form 3-Qs. The final rule generally adopts the changes provided in the Reporting NOPR. While the revisions will require additional time in the development of the report, the impact of the final rule is not expected to be material to Discovery.

On November 15, 2007, FERC issued a notice of proposed rulemaking proposing to permit market-based pricing for short-term capacity releases and to facilitate asset management arrangements by relaxing FERC s prohibition on tying and on its bidding requirements for certain capacity releases (Capacity Release NOPR). FERC proposes to lift the price ceiling for short-term capacity release transactions of one year or less. The Capacity Release NOPR is proposed to enable releasing shippers to offer competitively-priced alternatives to pipelines negotiated rates and to encourage more efficient construction of capacity. Under FERC s proposal, it is possible for the releasing shipper to release the natural gas at market-based prices while pipelines would still be subject to the maximum rate cap. On June 19, 2008, FERC issued Order No. 712 implementing revised capacity release rules that revised the capacity release regulations consistent with the Capacity Release NOPR.

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The most significant modification was to allow for capacity releases of one year or less to be awarded to the highest rate, without regard to the maximum rate. The impact of this rule to Discovery should be immaterial.

On December 21, 2007, FERC issued a notice of proposed rulemaking which proposes to require interstate natural gas pipelines and certain non-interstate natural gas pipelines to post capacity, daily scheduled flow information, and daily actual flow information. On November 20, 2008, FERC issued Order No. 720, a final rule adopting new regulations that require certain major non-interstate pipelines and interstate pipelines to publicly post certain operational and scheduling information. Interstate pipelines must post the volumes of no-notice transportation flows at each receipt and delivery point before 11:30 a.m. central clock time three days after the day of gas flow. The final rule requires interstate pipelines to post less information than under the proposed rule. The final rule does not apply to Discovery.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by the FERC and Congress, especially in light of potential market power abuse by marketing affiliates of certain pipeline companies engaged in interstate commerce. In response to this issue, Congress, in the Energy Policy Act of 2005 (EPACT 2005), and the FERC have implemented requirements to ensure that energy prices are not impacted by the exercise of market power or manipulative conduct. EPACT 2005 prohibits the use of any manipulative or deceptive device or contrivance in connection with the purchase or sale of natural gas, electric energy or transportation subject to the FERC s jurisdiction. The FERC then adopted the Market Manipulation Rules and the Market Behavior Rules to implement the authority granted under EPACT 2005. These rules, which prohibit fraud and manipulation in wholesale energy markets, are very vague and are subject to broad interpretation. Only two orders interpreting these rules have been issued to date, and each of these is subject to further proceedings. These orders reflect the FERC s view that it has broad latitude in determining whether specific behavior violates the rules. In addition, EPACT 2005 gave the FERC increased penalty authority for these violations. The FERC may now issue civil penalties of up to $1 million per day for each violation of FERC rules, and there are possible criminal penalties of up to $1 million and 5 years in prison. Given the FERC s broad mandate granted in EPACT 2005, it is assumed that if energy prices are high, or exhibit what the FERC deems to be unusual trading patterns, the FERC will investigate energy markets to determine if behavior unduly impacted or manipulated energy prices.

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. While the regulatory regime varies from state to state, state agencies typically require intrastate gas pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. 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 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. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by the FERC at least once every three years. The rate review may, but does not necessarily, involve an administrative-type hearing before the FERC staff panel and an administrative appellate review. 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. Among other matters, EPAct 2005 amends the NGPA to give

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FERC authority to impose civil penalties for violations of the NGPA up to $1,000,000 per day per violation for violations occurring after August 8, 2005. For violations occurring before August 8, 2005, FERC had the authority to impose civil penalties for violations of the NGPA up to $5,000 per violation per day. The Pelico and EasTrans systems are subject to FERC jurisdiction under Section 311 of the NGPA.

On December 21, 2007, FERC issued a notice of proposed rulemaking which proposes to require interstate natural gas pipelines and certain non-interstate natural gas pipelines to post capacity, daily scheduled flow information, and daily actual flow information. On November 20, 2008, FERC issued Order No. 720, a final rule adopting new regulations that require certain major non-interstate pipelines and interstate pipelines to publicly post certain operational and scheduling information. . Under the final rule, Order No. 720, major non-interstate gas pipelines must publicly post on a daily basis on an Internet web site (1) the design capacity of each receipt or delivery point that has a design capacity equal to or greater than 15,000 MMBtu/day, and (2) the amount scheduled at each such delivery point whenever capacity is scheduled. Order No. 720 defines a major non interstate pipeline as a company that is not an interstate pipeline and delivers annually more than fifty million MMBtu of natural gas measured in average deliveries for the previous three calendar years. The final rule exempts major non-interstate pipelines that lie entirely upstream of a processing, treatment, or dehydration plant. The implementation date is 150 days following the issuance of an order addressing the pending requests for rehearing. The Pelico and EastTrans Limited Partnership or East Trans systems are considered major non interstate pipelines and are required to comply with this rule. Compliance with this rule will result in additional administrative burdens related to the associated information technology costs.

On November 20, 2008, FERC issued an NOI to explore whether intrastate pipelines and Hinshaw pipelines providing interstate transportation and storage services should be required to post details of their transactions with shippers in a manner comparable to the posting requirements of interstate pipelines. Comments are due February 13, 2009. FERC s NOI is subject to change based on comments filed and therefore we cannot predict the scope of the final rulemaking.

The Discovery interstate natural gas pipeline system filed with FERC on November 16, 2007 a rate case settlement with a January 1, 2008 effective date. Also, modifications were made to the imbalance resolution and fuel reimbursement sections of Discovery s tariff. The settlement was approved on February 5, 2008 for all parties except ExxonMobil who contested the settlement. ExxonMobil will continue to pay the previous rates. ExxonMobil has an interruptible contract that was last used in 2006 so there will be no material impact by this outcome.

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 our natural gas pipelines 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 material, on-going litigation, 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.

Our purchasing, gathering and intrastate transportation operations are subject to ratable take and common purchaser statutes in the states in which they operate. 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

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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. 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. However, with regard to our physical purchases and sales of these energy commodities, and any related derivative activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission, or CFTC. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

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. 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.

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, 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.

In October 1992, Congress passed the Energy Policy Act of 1992, or EPAct, which among other things, required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for pipelines regulated by FERC pursuant to the ICA. The FERC responded to this mandate by issuing several orders, including Order No. 561. Beginning January 1, 1995, Order No. 561 enables petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. Specifically, the indexing methodology allows a pipeline to increase its rates annually by a percentage equal to the change in the producer price index for finished goods, PPI-FG, plus 1.3% to the new ceiling level. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline s increase in costs. If the PPI-FG falls and the indexing methodology results in a reduced ceiling level that is lower than a pipeline s filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling unless doing so would reduce a rate grandfathered by EPAct (see below) below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. The

FERC, however, retained cost-of-service ratemaking, market based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. The FERC s indexing methodology is subject to review every five years; the current methodology is expected to remain in place through

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June 30, 2011. If the FERC continues its policy of using the PPI-FG plus 1.3%, changes in that index might not fully reflect actual increases in the costs associated with the pipelines subject to indexing, thus hampering our ability to recover cost increases.

EPAct deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct that had not been subject to complaint, protest or investigation during that 365-day period to be just and reasonable under the ICA. Generally, complaints against such grandfathered rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPAct in either the economic circumstances of the petroleum pipeline, or in the nature of the services provided, that were a basis for the rate. EPAct places no such limit on challenges to a provision of a petroleum pipeline tariff as unduly discriminatory or preferential.

The pending FERC proceeding regarding the appropriate composition of proxy groups for purposes of determining equity returns to be included in cost-of-service based rates is also applicable to FERC-regulated oil pipelines. On April 17, 2008, FERC issued a final policy statement regarding the appropriate composition of proxy groups. FERC concluded, among other things, that MLPs should be included in the ROE proxy group for both oil and gas pipelines. FERC established a paper hearing for establishing the ROE for cases that were pending before FERC. The policy statement could result in the establishment of a higher ROE in future rate proceedings but the full effect is uncertain until the policy is applied.

Intrastate NGL Pipeline Regulation

Intrastate NGL and other petroleum pipelines 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. While the regulatory regime varies from state to state, state agencies typically require intrastate petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

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:

- requiring the acquisition of permits to conduct regulated activities;
- 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. 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. For instance, 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. 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. Below is a discussion of the more significant environmental laws and regulations that relate to our business and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Air Emissions

Our operations are subject to the federal Clean Air Act, as amended 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 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. Following the performance of an audit by us during 2007 on facilities included in our Northern Louisiana system, we identified and subsequently self-disclosed to the Louisiana Department of Environmental Quality alleged violations of environmental law arising primarily from historical operations at certain of those facilities. We are currently involved in settlement discussions with the Louisiana Department of Environmental Quality to resolve these alleged matters. In addition, The Colorado Department of Public Health and Environment, or CDPHE, has alleged violations of the environmental permit at the Anderson Gulch Gas Plant, as a result of an inspection in January 2008. The allegations are primarily related to recordkeeping requirements. We are currently in settlement discussions with the CDPHE to resolve this matter. Aside from these enforcement matters, we believe that we are in material compliance with these requirements. We do not believe our future operations will be materially adversely affected by such requirements or enforcement matters.

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, as amended, or CERCLA, also known as 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. 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, as amended, 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 properties where petroleum 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, petroleum 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 petroleum 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 petroleum 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, as amended, 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.

Global Warming and Climate Change

In response to recent studies suggesting that emissions of carbon dioxide and certain other gases often referred to as greenhouse gases may be contributing to warming of the Earth s atmosphere, the current session of the U.S. Congress is considering climate change-related legislation to regulate greenhouse gas emissions. In addition, at least one-third of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations (*e.g.*, compressor units) or from combustion of fuels (*e.g.*, oil or natural gas) we process. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate carbon dioxide and other greenhouse gas emissions from mobile sources such as cars and trucks, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address carbon dioxide and other greenhouse gas emissions from vehicles and automobile fuels, although the date for issuance of this notice has not been finalized. The Court s holding in the *Massachusetts* decision that greenhouse gases including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain CAA programs. New federal or state laws requiring adoption of a stringent greenhouse gas control program or imposing restrictions on emissions of carbon dioxide in areas of the United States in which we conduct business could adversely affect our cost of doing business and demand for the oil and gas we transport.

Anti-Terrorism Measures

The federal Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, known as the Chemical Facility Anti-Terrorism Standards interim rule, including oil and gas facilities that are deemed to present high levels of security risk. The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to the act and, on November 20, 2007, further issued an Appendix A to the interim rules that established chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Facilities possessing greater than threshold levels of these chemicals of interest were required to prepare and submit to the DHS in January 2008 initial screening surveys that the agency would use to determine whether the facilities presented a high level of security risk. Covered facilities that are determined by DHS to pose a high level of security risk will be notified by DHS and will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. We have not yet determined the extent to which our facilities are subject to the interim rules or the associated costs to comply, but it is possible that such costs could be material.

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, 2008, the General Partner or its affiliates employed 10 people directly and approximately 138 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.

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, which are 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 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 continue to make cash distributions to holders of our common units at our current distribution rate.

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 success of our commodity derivative and interest rate hedging programs in mitigating fluctuations in commodity prices and interest rates;
- 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, NGL and crude oil prices;
- the level of competition from other 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 for acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets at reasonable rates;

restrictions contained in our debt agreements;

the amount of cash distributions we receive from our equity interests; and

the amount of cash reserves established by our general partner.

We have partial ownership interests in a number of joint venture legal entities, including Discovery, East Texas and Black Lake, which could adversely affect our ability to operate and control these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to you.

Our inability, or limited ability, to control the operations and management of joint venture legal entities that we have a partial ownership interest in may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for entities where we have a minority ownership interest, we will be unable to control ongoing operational decisions, including the incurrence of capital expenditures that we may be required to fund. Specifically,

- We have limited ability to influence decisions with respect to the operations of these entities and their subsidiaries, including decisions with respect to incurrence of expenses and distributions to us;
- These entities may establish reserves for working capital, capital projects, environmental matters and legal proceedings which would otherwise reduce cash available for distribution to us;
- These entities may incur additional indebtedness, and principal and interest made on such indebtedness may reduce cash otherwise available for distribution to us; and
- These entities may require us to make additional capital contributions to fund working capital and capital expenditures, our funding of which could reduce the amount of cash otherwise available for distribution.

All of these items could significantly and adversely impact our ability to distribute cash to the unitholders.

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

Profitability may be significantly 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.

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 assets, 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 lower than in recent periods. For example, the rolling twelve-month average New York Mercantile Exchange, or NYMEX, daily settlement price of natural gas futures contracts per MMBtu was $6.21, $7.96 and $7.23 as of December 31, 2008, 2007 and 2006 respectively. During periods of natural gas price 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 borrow funds and access capital markets at reasonable rates, the ability of producers to obtain necessary drilling and other governmental permits, 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, or declines 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 position and cash flows.

The cash flow from our Natural Gas Services segment is affected by natural gas, NGL and condensate prices.

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, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, or extreme weather that may disrupt our operations or related downstream operations;
- the level of domestic and offshore production;
- a general downturn in economic conditions, including demand for NGLs;
- the availability of imported natural gas, NGLs and crude oil and the demand in the U.S. and globally for these commodities;
- 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 extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. Under percent-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 mitigated a significant portion of our share of anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with derivative instruments.

Our derivative activities and the application of fair value measurements may have a material adverse effect on our earnings, profitability, cash flows, liquidity and financial condition.

We are 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 derivative 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. To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have primarily entered into derivative financial instruments relating to the future price of crude oil. If the price relationship between NGLs and crude oil changes, our commodity price risk may increase. 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 open 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, reducing our liquidity.

We have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes from our gathering and processing operations through 2013 by entering into derivative financial instruments relating to the future price of natural gas and crude oil. Additionally, we have entered into interest rate swap agreements to convert a portion of the variable rate revolving debt under our 5-year credit agreement that matures in June 2012, or the 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 record all of our derivative financial instruments at fair value on our balance sheets primarily using information readily observable within the marketplace. In situations where market observable information is not available, we may use a variety of data points that are market observable, or in certain instances, develop our own expectation of fair value. We will continue to use market observable information as the basis for our fair value calculations, however, there is no assurance that such information will continue to be available in the future. In such instances we may be required to exercise a higher level of judgment in developing our own expectation of fair value, which may be significantly different from the historical fair values, and may increase the volatility of our earnings.

We will continue to evaluate whether to enter into any new derivative arrangements, but there can be no assurance that we will enter into any new derivative arrangement or that our future derivative arrangements will be on terms similar to our existing derivative arrangements. Although we enter into derivative instruments to mitigate our commodity price and interest rate risk, we also forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

The counterparties to our derivative instruments may require us to post collateral in the event that our potential payment exposure exceeds a predetermined collateral threshold. Depending on the movement in commodity prices, the amount of collateral posted may increase, reducing our liquidity.

As a result of these factors, our derivative 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 derivative activities, these activities can result in material losses. Such losses could occur under various circumstances, including if a counterparty does not or is unable to perform its obligations under the applicable derivative arrangement, the derivative arrangement is imperfect or ineffective, or our risk management policies and procedures are not properly followed or do not work as planned.

Volumes of natural gas dedicated to our systems in the future may be less than we anticipate.

As a result of the unwillingness of producers to provide reserve information as well as the cost of such evaluation, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the reserves connected to our gathering systems are 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.

We depend on certain natural gas producer customers for a significant portion of our supply of natural gas and NGLs.

We identify as primary natural gas suppliers those suppliers individually representing 10% or more of our total natural gas supply. Our two primary suppliers of natural gas represented approximately 30% of the natural gas supplied in our

Natural Gas Services segment during the year ended December 31, 2008. 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.

If we are not able to purchase propane from our principal suppliers, or we are unable to secure transportation under our transportation arrangements, 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. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our three primary suppliers of propane, two of which are affiliated entities, represented approximately 82% of our propane supplied during the year ended December 31, 2008. In the event that we are unable to purchase propane from our significant suppliers or replace terminated or expired supply contracts, our failure to obtain alternate sources of supply at competitive prices and on a timely basis would affect our ability to satisfy customer demand, reduce our revenues and adversely affect our results of operations. In addition, if we are unable to transport propane supply to our terminals under our rail commitments, our ability to satisfy customer demand and our revenue and results of operations would be adversely affected.

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 liabilities associated with acquired businesses or assets;
- integrate 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. 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.

Furthermore, we have recently grown significantly through a number of acquisitions. For example, in May 2007 we acquired the southern Oklahoma system, in July 2007 we acquired a 25% interest in East Texas and a 40% interest in Discovery from DCP Midstream, LLC, in August 2007 we acquired certain subsidiaries of MEG that hold our

Douglas and Collbran assets from DCP Midstream, LLC and in October 2008, we acquired the Michigan assets. If we fail to properly integrate these acquired assets successfully with our existing operations, if the future performance of these acquired assets does not meet our expectations, or we did not identify significant liabilities associated with the acquired assets, the anticipated benefits from these acquisitions may not be fully realized.

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We may not successfully balance our purchases and sales of natural gas and propane.

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. 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 NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce the volume of natural gas processed at plants connected to our NGL pipelines, as well as reducing the amount of NGL extraction, which would reduce the volumes and gross margins attributable to our NGL pipelines.

Third party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities may become unavailable to transport or produce natural gas and NGLs.

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. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control.

Service at our propane terminals may be interrupted.

Historically, a substantial portion of the propane we purchase to support our wholesale propane logistics business is delivered at our rail terminals or by ship at our leased marine terminal in Providence, Rhode Island. We also rely on shipments of propane via the Buckeye Pipeline for our Midland Terminal and 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 and impact our revenues or cash available for distribution.

We operate in a highly competitive business environment.

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. Likewise, our customers who produce NGLs may develop their own systems to transport NGLs. Additionally, our wholesale propane distribution customers may develop their own sources of propane supply. 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.

Weather conditions, such as warm winters, principally in the northeastern United States, may affect the overall demand for propane.

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. 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.

Competition from alternative energy sources, conservation efforts and energy efficiency and technological advances may reduce the demand for propane.

Competition from alternative energy sources, including natural gas and electricity, has been increasing as a result of reduced regulation of many utilities. 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, energy generation or other devices could reduce the demand for propane.

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.

The majority of our natural gas gathering and intrastate transportation operations are exempt from FERC regulation under the NGA 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 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 the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on any reassessment by us of the jurisdictional status of our facilities or 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 and the EasTrans Limited Partnership or EasTrans pipeline system owned by East Texas, are 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 EasTrans system is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under an order approved by the Railroad Commission of Texas. 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.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPAct 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1,000,000 per day for each violation.

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

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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 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 are currently 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.

Discovery s interstate tariff rates are subject to review and possible adjustment by federal regulators. Moreover, because Discovery is a non-corporate entity, it may be disadvantaged in calculating its cost-of-service for rate-making purposes.

The FERC, pursuant to the NGA, regulates many aspects of Discovery s interstate pipeline transportation service, including the rates that Discovery is permitted to charge for such service. Under the NGA, interstate transportation rates must be just and reasonable and not unduly discriminatory. If the FERC fails to permit tariff rate increases requested by Discovery, or if the FERC lowers the tariff rates Discovery is permitted to charge its customers, on its own initiative, or as a result of challenges raised by Discovery s customers or third parties, Discovery s tariff rates may be insufficient to recover the full cost of providing interstate transportation service. In certain circumstances, the FERC also has the power to order refunds.

The Discovery interstate natural gas pipeline system filed with FERC on November 16, 2007 a rate case settlement with a January 1, 2008 effective date. Also, modifications were made to the imbalance resolution and fuel reimbursement sections of Discovery s tariff. FERC approved the settlement on February 5, 2008 for all parties except ExxonMobil who contested the settlement. ExxonMobil will continue to pay the previous rates.

Under current policy, the FERC permits pipelines to include, in the cost-of-service used as the basis for calculating the pipeline s regulated rates, a tax allowance reflecting the actual or potential income tax liability on public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. In a future rate case, Discovery may be required to demonstrate the extent to which inclusion of an income tax allowance in Discovery s cost-of-service is permitted under the current income tax allowance policy.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPAct 2005 FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,000,000 per day for each violation.

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, NGLs 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 governmental claims for natural resource damages or fines or penalties for related violations of environmental laws or regulations. In addition, it is possible 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 some or any of these costs from insurance or from indemnification from DCP Midstream, LLC.

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

Pursuant to the Pipeline Safety Improvement Act of 2002, the 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.

Although many of our natural gas facilities fall within a class that is not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with non-exempt pipeline. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, we may be affected by the testing, maintenance and repair of pipeline facilities downstream from our own facilities. Our NGL pipelines are also subject to integrity management and other safety regulations imposed by the Texas Railroad Commission, or TRRC.

We currently estimate that we will incur costs of approximately $2.0 million between 2009 and 2013 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.

We currently transport all of the NGLs produced at our Minden plant on the Black Lake pipeline. Accordingly, 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.

Any regulatory expansion of the existing pipeline safety requirements or the adoption of new pipeline safety requirements could also increase our cost of operation and impair our ability to provide service during the period in which assessments and repairs take place, adversely affecting our business.

Construction of new assets is subject to regulatory, environmental, political, legal, economic and other risks that may adversely affect financial results.

The construction of additions or modifications to our existing midstream asset systems or propane terminals involves numerous regulatory, environmental, political and legal and economic uncertainties beyond our control and may require the expenditure of significant amounts of capital. These projects may not be completed on schedule or within budgeted cost, or at all. 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. 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. The construction of additions to our existing gathering, transportation and propane terminal assets may require us to rely on third parties downstream of our facilities to have available capacity for our delivered natural gas, natural gas liquids, or propane. If such third party facilities are not constructed or operational at the time that the addition to our facilities is completed, we may experience adverse effects on our results of operations and financial condition. The construction of additional propane terminals may require greater capital investment if the commodity prices of certain supplies such as steel increase. Construction also subjects us to risks related to the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control that could adversely affect results of operations, financial position or cash flows.

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

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants. Our ability to make acquisitions that are accretive to our cash generated from operations per unit is based upon our ability to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them and obtain financing for these acquisitions on economically acceptable terms. 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, future contract terms with customers, revenues and costs, including synergies;

an inability to successfully integrate the businesses we acquire;

the assumption of unknown liabilities;

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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;

change in competitive landscape;

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 unitholders 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.

In addition, any limitations on our access to substantial new capital to finance strategic acquisitions will impair our ability to execute this component of our growth strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of capital include market conditions and offering or borrowing costs such as interest rates or underwriting discounts.

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

Upon contract lease renewal, we may be subject to 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 business involves many hazards and operational risks, some of which may not be fully covered by insurance.

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. 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. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage, or may become prohibitively expensive, and we may elect not to carry policy.

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Recent turmoil in the capital markets may adversely impact our liquidity.

The capital markets have recently experienced volatility, uncertainty and interventions by various governments around the globe. This turmoil in the global capital markets has caused significant financial uncertainty. Our access to funds under the Credit Agreement is dependent on the ability of the lenders that are party to the Credit Agreement to meet their funding obligations. Those lenders may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Lehman Brothers Commercial Bank, or Lehman Brothers, a lender to the Credit Agreement, has failed to fund under that agreement since its bankruptcy. Accordingly, the capacity under our Credit Agreement is approximately $824.6 million, excluding Lehman Brothers unfunded commitment. If additional lenders under the Credit Agreement were to fail to fund their share of the Credit Agreement, our available borrowings could be further reduced. In addition, our borrowing capacity may be further limited by the Credit Agreement s financial covenant requirements.

A significant downturn in the economy could adversely affect our results of operations, financial position or cash flows. In the event that our results were negatively impacted, we could require additional funds for working capital purposes. The recent turmoil in the capital markets has resulted in significantly higher costs of public debt and equity funds and reduced funding capabilities generally. Further deterioration in the capital markets could adversely affect our ability to access funds on reasonable terms in a timely manner.

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

Our Credit Agreement has capacity of approximately $824.6 million, assuming no capacity related to Lehman Brothers unfunded commitment, matures on June 21, 2012, and consists of a $764.6 million revolving credit facility and a $60.0 million term loan facility for working capital and other general corporate purposes. As of December 31, 2008, the outstanding balance on the revolving credit facility was $596.5 million and the outstanding balance on the term loan facility was $60.0 million.

We continue to have the ability to incur additional debt, subject to limitations within 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;
- an increased amount of cash flow will be required to make interest payments on our debt;
- 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. In addition, our ability to service debt under our revolving credit facility will depend on market interest rates. If our operating results are not sufficient to service our current or future indebtedness, we may 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.

Restrictions in our credit facility may limit our ability to make distributions to unitholders 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.

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Changes in interest rates may adversely impact our ability to issue additional equity or incur debt, as well as the ability of exploration and production companies to finance new drilling programs around our systems.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. 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 impair our ability to issue additional equity to make acquisitions, or incur debt or for other purposes. Increased interest costs could also inhibit the financing of new capital drilling programs by exploration and production companies served by our systems.

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

We rely on the cash flow 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, an adverse development in one of these businesses may have a significant impact on our company.

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, the threat of terrorist attacks, and 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.

Risks Inherent in an Investment in Our Common Units

Conflicts of interest may exist between individual unitholders and DCP Midstream, LLC, our general partner, which has sole responsibility for conducting our business and managing our operations.

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 and our unitholders. 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;

once certain requirements are met, 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;

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, as amended, between us, DCP Midstream, LLC and others will prohibit DCP Midstream, LLC and its affiliates, including ConocoPhillips, Spectra Energy and Spectra Energy Partners, LP, 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 material.

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 material. 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. These factors may 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.

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 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. This may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at a time 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. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level.

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, in certain situations, 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 our general partner will be chosen by the members of 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. As of December 31, 2008, our general partner and its affiliates owned approximately 30% of our aggregate outstanding 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.

If we are deemed an investment company under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our current assets include a 25% interest in East Texas, a 40% interest in Discovery, a 45% interest in Black Lake and investments in certain commercial paper and other high grade debt securities, some or all of which may be deemed to be investment securities within the meaning of the Investment Company Act of 1940. If a sufficient amount of our assets are deemed to be investment securities within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the Commission or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes, and be subject to federal income tax at the corporate tax rate, significantly reducing the cash available for distributions. Additionally, distributions to the unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to the unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in East Texas, Discovery or Black Lake.

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

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

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

Certain of our investors, including affiliates of our general partner, may sell units in the public or private markets, which could reduce the market price of our outstanding common units.

Pursuant to agreements with investors in private placements effected in 2007, we have filed a registration statement on Form S-3 registering issuances by unitholders of an aggregate of 5,386,732 of our common units. In addition, in February 2008, we satisfied the financial tests contained in our partnership agreement for the early conversion of 3,571,428, or 50%, of the outstanding subordinated units held by DCP Midstream, LLC into common units, and on February 17, 2009, we satisfied the financial tests contained in our partnership agreement for the early conversion of the remaining 3,571,429 outstanding subordinated units held by DCP Midstream, LLC into common units. After the conversion, DCP Midstream, LLC holds 8,246,451 common units.

If investors or affiliates of our general partner holding these units were to dispose of a substantial portion of these units in the public market, whether in a single transaction or series of transactions, it could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Our general partner has a limited call right that may require the unitholders to sell their 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, the unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their 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

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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 the unitholders 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 being subject to minimal entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation or we become subject to a material amount of 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 IRS regarding our status as a partnership.

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions to 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, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, which would cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these amendments or other proposals will ultimately be enacted. Moreover, any such modification to federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such legislative changes could negatively impact the value of an investment in our common units. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year and a Michigan business tax of 0.8% on gross receipts, and 4.95% of Michigan taxable income. Imposition of such a tax on us by any other state will reduce the cash available for distribution to the unitholder. 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.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted, 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. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this document or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not agree with some or all of our counsel s conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because such 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, the unitholder 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. The 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. Because distributions to the unitholders in excess of the total net taxable income allocated to them for a common unit decreases their tax basis in that common unit, the amount, if any, of such prior excess distributions 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. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, 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 non-U.S. 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, which may be taxable to them. Distributions to non-U.S. persons will be reduced by federal 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 non-U.S. person, they should consult their tax advisor before investing in our common units.

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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 adopt 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 the unitholders tax returns.

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

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

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

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

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedule K-1 s) for one fiscal year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

Unitholders may be subject to state and local taxes and return filing requirements in states where they do not reside as a result of investing in our units.

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 conduct business or own property, even if the unitholder does 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 conduct business in the states of Arkansas, Colorado, Connecticut, Indiana, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Texas, Vermont, Virginia, West Virginia and Wyoming. Each of these states, other than Texas and Wyoming, currently imposes a personal income tax on individuals. A majority of these states impose an income tax on corporations and other entities. 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 the unitholder s responsibility to file all United States federal, foreign, state and local tax returns.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

As of February 23, 2009, we owned and operated processing plants and gathering systems located in Arkansas, Colorado, Louisiana, Michigan, Oklahoma, and Wyoming, all within our Natural Gas Services segment, six propane rail terminals located in the midwest and northeastern United States, one of which is was idled in 2007 to consolidate our operations, and one propane pipeline terminal located in Pennsylvania within our Wholesale Propane Logistics Segment, and two pipelines located in Texas within our NGL Logistics segment. In addition, we own (1) a 40% interest in Discovery Producer Services, LLC, which owns an offshore gathering pipeline, a natural gas processing plant and an NGL fractionator plant in Louisiana operated by a third party, and (2) a 25% interest in DCP East Texas Holdings, LLC, which owns a natural gas processing complex in Texas, all within our Natural Gas Services Segment. We also own a 45% interest in the Black Lake pipeline located in Louisiana and Texas operated by a third party within our NGL Logistics segment, and a 50% interest in a propane rail terminal located in Maine 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 suitable and adequate to carry on our business at capacity for the foreseeable future.

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.

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

Item 3. *Legal Proceedings*

We are not a party to any significant legal proceedings, other than those listed below, 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.

Driver In August 2007, Driver Pipeline Company, Inc., or Driver, filed a lawsuit against DCP Midstream, LP, an affiliate of the owner of our general partner, in District Court, Jackson County, Texas. The litigation stems from an ongoing commercial dispute involving the construction of our Wilbreeze pipeline, which was completed in December 2006. Driver was the primary contractor for construction of the pipeline and the construction process was managed for us by DCP Midstream, LP. Driver claims damages in the amount of $2.4 million for breach of contract. We believe Driver s position in this litigation is without merit and we intend to vigorously defend ourselves against this claim. 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.

El Paso On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved, in accordance with accounting principles generally accepted in the United States of America, a contingent liability of $2.5 million for this matter, which is included in our consolidated financial statements for the year ended December 31, 2008. This reserve changes our financial results as reported in our earnings release dated February 25, 2009, which date preceded the jury verdict.

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 2008.

PART II

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

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 2008 and 2007.

Quarter Ended	High	Low	Distribution Per Common Unit	Distribution Per Subordinated Unit
December 31, 2008	$ 16.94	$ 5.75	$ 0.600	$ 0.600
September 30, 2008	$ 30.21	$ 16.92	$ 0.600	$ 0.600
June 30, 2008	$ 31.51	$ 28.98	$ 0.600	$ 0.600
March 31, 2008	$ 43.51	$ 27.37	$ 0.590	$ 0.590
December 31, 2007	$ 45.95	$ 37.68	$ 0.570	$ 0.570
September 30, 2007	$ 50.50	$ 41.75	$ 0.550	$ 0.550
June 30, 2007	$ 47.00	$ 38.15	$ 0.530	$ 0.530
March 31, 2007	$ 40.06	$ 33.99	$ 0.465	$ 0.465

As of February 23, 2009, there were approximately 47 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.

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Issuance of Unregistered Units

In February 2008, we satisfied the financial tests contained in our partnership agreement for the early conversion of 50% of the outstanding subordinated units held by DCP Midstream, LLC into common units on a one-for-one basis. Before the conversion, DCP Midstream, LLC held 7,142,857 subordinated units, and after the conversion, DCP Midstream, LLC held 3,571,429 subordinated units. On February 17, 2009, we satisfied the financial tests contained in our partnership agreement for the early conversion of the remaining 3,571,429 outstanding subordinated units held by DCP Midstream, LLC into common units on a one for one basis.

Distributions of Available Cash

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

In January 2008, our registration statement on Form S-3 to register the 3,005,780 common limited partner units represented in the June 2007 private placement agreement and the 2,380,952 common limited partner units represented in the August 2007 private placement agreement was declared effective by the SEC.

In March 2008, we issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of $132.1 million, net of offering costs.

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;
  - 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 $0.60 per unit, or $2.40 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 Prior to June 2007, our general partner was entitled to 2% of all quarterly distributions since inception that we made. 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 has not participated in certain issuances of common units. Therefore, the general partner s 2% interest has been diluted to approximately 1% as of December 31, 2008. The general partner s interest may be further 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 current general partner interest.

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The incentive distribution rights held by our general partner entitle it to receive an increasing share of Available Cash as pre-defined distribution targets have been achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. Our general partner s incentive distribution rights were not reduced as a result of our March 2008 common limited partner unit offering, and will not 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 current general partner interest. Please read the *Distributions of Available Cash during the Subordination Period* and *Distributions of Available Cash after the Subordination Period* sections in Note 12 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data for more details about the distribution targets and their impact on the general partner s incentive distribution rights.

On January 27, 2009, the board of directors of DCP Midstream GP, LLC declared a quarterly distribution of $0.60 per unit, which was paid on February 13, 2009, to unitholders of record on February 6, 2009.

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.

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Item 6. *Selected Financial Data*

The following table shows our selected financial data for the periods and as of the dates indicated, which is derived from the consolidated financial statements. These 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, or DCP Midstream Partners Predecessor, upon the closing of our 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, and our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services, LLC, or Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007. These were transactions among entities under common control; accordingly, our financial information includes the historical results of our wholesale propane logistics business, Discovery and East Texas for all periods presented. 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.

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

	Year Ended December 31,				
	2008(a)	2007(a)	2006	2005	2004
	(Millions, except per unit data)				
Statements of Operations Data:					
Total operating revenues(b)	$ 1,285.8	$ 873.3	$ 795.8	$ 1,144.3	$ 834.0
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	1,061.2	826.7	700.4	1,047.3	760.6
Operating and maintenance expense	43.0	32.1	23.7	22.4	19.8
Depreciation and amortization expense	36.5	24.4	12.8	12.7	14.7
General and administrative expense	24.0	24.1	21.0	14.2	8.7
Other	(1.5)				
Total operating costs and expenses	1,163.2	907.3	757.9	1,096.6	803.8
Operating income (loss)	122.6	(34.0)	37.9	47.7	30.2
Interest income	5.6	5.3	6.3	0.5	
Interest expense	(32.8)	(25.8)	(11.5)	(0.8)	
Earnings from equity method investments(c)	34.3	39.3	29.2	25.7	17.6
Impairment of equity method investment(d)					(4.4)
Non-controlling interest in income	(3.9)	(0.5)			
Income tax expense(e)	(0.1)	(0.1)		(3.3)	(2.5)

Net income (loss)	$ 125.7	$ (15.8)	$ 61.9	$ 69.8	$ 40.9
Less:					
Net income attributable to predecessor operations(f)		(3.6)	(26.6)	(65.1)	(40.9)
General partner interest in net income	(11.9)	(2.2)	(0.7)	(0.1)	
Net income (loss) allocable to limited partners	$ 113.8	$ (21.6)	$ 34.6	$ 4.6	$
Net income (loss) per limited partner unit-basic and diluted	$ 3.25	$ (1.05)	$ 1.90	$ 0.20	$

	Year Ended December 31,				
	2008(a)	2007(a)	2006	2005	2004
	(Millions, except per unit data)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 629.3	$ 500.7	$ 194.7	$ 178.7	$ 179.3
Total assets	$ 1,180.0	$ 1,120.7	$ 665.9	$ 680.1	$ 472.5
Accounts payable	$ 78.4	$ 165.8	$ 117.3	$ 138.3	$ 63.5
Long-term debt	$ 656.5	$ 630.0	$ 268.0	$ 210.1	$
Partners equity	$ 329.1	$ 168.4	$ 267.7	$ 320.7	$ 400.5
Other Information:					
Cash distributions declared per unit	$ 2.390	$ 2.115	$ 1.565	$ 0.095	N/A
Cash distributions paid per unit	$ 2.360	$ 1.975	$ 1.230	N/A	N/A

(a) Includes the effect of the acquisition of the Southern Oklahoma system in May 2007, certain subsidiaries of Momentum Energy Group, Inc. in August 2007 and Michigan Pipeline & Processing, LLC in October 2008.

(b) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap was for a total of approximately 1.9 million barrels at $66.72 per barrel.

(c) Includes the effect of the acquisition of a 25% limited liability company interest in East Texas and a 40% limited liability company interest in Discovery for all periods presented, as well our proportionate share of the earnings of Black Lake, East Texas and Discovery. Earnings for Discovery and Black Lake include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the investments.

(d) In 2004, we recorded our proportionate share of an impairment charge on Black Lake totaling $4.4 million.

(e) Income tax expense for 2004 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. Income tax expense in 2008 and 2007 represents a margin-based franchise tax in Texas, or the Texas margin tax and a Michigan business tax. See Note 15 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

(f) Includes the net income attributable to DCP Midstream Partners Predecessor through December 7, 2005, 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, and the net income attributable to the acquisition of a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, and the Swap prior to the date of our acquisition from DCP Midstream, LLC in July 2007.

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, which we acquired from DCP Midstream, LLC in

November 2006, and our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services, LLC, or Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007. We refer to DCP Midstream Partners Predecessor, our wholesale propane logistics business, East Texas and Discovery *collectively as our predecessors. The financial information contained herein includes, for each period presented, our accounts, and those of our predecessors.*

Overview

We are a Delaware limited partnership formed by DCP Midstream, 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 (1) our Northern Louisiana natural gas gathering, processing and transportation system; (2) our Southern Oklahoma system acquired in May 2007; (3) our limited liability company interest in East Texas, our limited liability company interest in Discovery, and the Swap, acquired in July 2007 from DCP Midstream, LLC; (4) our Colorado and Wyoming systems, acquired in August 2007 from DCP Midstream, LLC, which were acquired by DCP Midstream, LLC from Momentum Energy Group, Inc., or MEG, in August 2007 (referred to as the MEG acquisition); and (5) our Michigan systems, acquired in October 2008 from Michigan Pipeline & Processing, LLC (referred to as the MPP acquisition);

our Wholesale Propane Logistics segment, which consists of six owned rail terminals, one of which was idled in 2007 to consolidate our operations, one leased marine terminal, one pipeline terminal which became operational in May 2007, and access to several open access pipeline terminals; and

our NGL Logistics segment, which consists of our Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated equity interest in the Black Lake interstate NGL pipeline.

The financial information contained herein includes, for each period presented, our accounts, and the assets, liabilities and operations of (1) DCP Midstream Partners Predecessor for periods prior to December 7, 2005, (2) our wholesale propane logistics business that we acquired in November 2006 and (3) our 25% interest in East Texas, 40% interest in Discovery, and the Swap that we acquired in July 2007, from DCP Midstream, LLC in transactions among entities under common control. Accordingly, our financial information includes the historical results of our predecessors 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

On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved in accordance with accounting principles generally accepted in the United States of America, or GAAP, a contingent liability of $2.5 million for this matter, which is included in our consolidated financial statements for the year ended December 31, 2008. This reserve changes our financial results as reported in our earnings release dated February 25, 2009, which date preceded the jury verdict.

On February 25, 2009, we entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC will contribute an additional 25.1% interest in East Texas to us in exchange for 3.5 million Class D units, providing us with a 50.1% interest in East Texas following the expected closing of the transaction in April 2009. This closing date is subject to extension for up to 45 days to allow for repairs or replacement to our reasonable satisfaction any assets destroyed or damaged by certain casualty losses and time to enable the plant to process all available inlet volumes as defined in the Contribution Agreement. The Class D units will automatically convert into common units in August 2009 and will not be eligible to receive a distribution until the second quarter distribution payable in August 2009. DCP Midstream, LLC has agreed to provide a fixed-price NGL derivative by NGL component for the period of April 2009 to March 2010 for the acquired interest. Subsequent to this transaction, we will consolidate East Texas in our consolidated financial statements.

On February 11, 2009, we announced, along with DCP Midstream, LLC, that our East Texas natural gas processing complex and residue natural gas delivery system known as the Carthage Hub, have been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. No employees or contractors were injured in the incident. There was no significant damage to the natural gas processing complex. As of February 25, 2009, the complex began processing through one of the five plants, and it is expected that full processing capacities will be restored for the entire complex over the next 30 days. Residue gas will be redelivered into limited available pipeline interconnects while the Carthage Hub undergoes inspection and repairs.

On February 17, 2009, the remaining 3,571,429 DCP Partners subordinated units were converted to common units following the completion of the subordination period and satisfactory completion of all subordination period tests contained in the DCP Partners partnership agreement.

In February 2009, we entered into interest rate swap agreements to convert $275.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to interest rate fluctuations. These interest rate swaps commence in December 2010 and expire in June 2012. In November 2008, we entered into interest rate swap agreements to convert $150.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to interest rate fluctuations. These interest rate swaps expire in December 2010.

As a result of hurricanes during the third quarter of 2008, certain of our owned and operated facilities were fully or partially curtailed pending resumption of electric power and operations at downstream third party NGL facilities, in some cases. All of our operated assets have since been returned to service. There has been some temporary impact to demand as third party NGL facilities are returned to service. The net income impact of hurricane-related damages and lost margins due to curtailed operations for the third and fourth quarters of 2008 was approximately $14.7 million, including losses from our equity method investment in Discovery.

In January 2009, repairs were completed on Discovery s 30-inch mainline, restoring approximately 85% of volumes and margins to the system. With the completion of the 18-inch lateral repairs, the remaining volumes are expected to be restored in early March. We did not receive a fourth quarter distribution from Discovery, which would have been paid during January 2009. We anticipate distributions to resume for the first quarter of 2009, which will be paid in April 2009. Discovery s offshore gathering system had been damaged by hurricane Ike in September 2008 when an 18-inch lateral was severed from its connection to the 30-inch mainline in 250 feet of water.

On January 27, 2009, the board of directors of the general partner declared a quarterly distribution of $0.60 per unit, payable on February 13, 2009 to unitholders of record on February 6, 2009.

In January 2009, Don Baldridge was appointed to Vice President, Business Development. Previously, Mr. Baldridge was Vice President, Corporate Development for DCP Midstream, LLC. Mr. Baldridge is replacing Greg K. Smith, who was appointed Vice President, Gas Supply for DCP Midstream, LLC.

In early January 2009, the second phase of our Wyoming pipeline and systems enhancement project was completed, returning over 80% of the system volumes to service. The final phase is on target for completion in March.

In December 2008, we made contributions of $1.9 million to Discovery, $1.6 million of which was to fund hurricane damages and $0.3 million was to fund capital expansion. In December 2008 we received a distribution of $2.5 million from East Texas and paid a contribution of $2.6 million to East Texas to fund capital expansion.

In October 2008, due to executive management rotational changes at ConocoPhillips, Willie C.W. Chiang and Sigmund L. Cornelius resigned as directors of the board of directors of our general partner, and John E.

Lowe and Gregory J. Goff were appointed as the ConocoPhillips representatives to the board of directors. Mr. Lowe currently serves as assistant to the Chief Executive Officer of ConocoPhillips, an affiliate of our general partner and Mr. Goff currently serves as Senior Vice President, Commercial of ConocoPhillips. Mr. Goff was also appointed to DCP Partners compensation committee in December 2008.

In October 2008, we acquired Michigan Pipeline & Processing, LLC, or MPP, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.4 million, subject to additional customary purchase price adjustments, plus up to an additional $15.0 million to the sellers depending on the earnings of the assets after a three-year period. We financed the acquisition through utilization of our credit facility. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay us up to $1.5 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments would reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. Certain of these performance criteria were satisfied, and as a result, the amount has been reduced to $0.8 million per year as of February 23, 2009. We initially held a $25.0 million letter of credit to secure the seller s performance under this agreement and to secure the seller s indemnification obligation under the acquisition agreement; however as a result of the satisfaction of certain performance conditions, this amount has been reduced to $22.5 million as of February 23, 2009. The fees under the omnibus agreement with DCP Midstream, LLC increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

Factors That Significantly Affect Our Results

Capital Markets

Beginning in the third quarter of 2008, the capital markets experienced volatility, uncertainty and interventions by various governments around the globe. The effects of these market conditions include significant changes in the valuation of equity securities and overnight and longer-term borrowing rates. The availability of credit through traditional sources of funding such as the commercial paper, bank lending and the private and public placement debt markets also decreased dramatically. The uncertainty in the capital markets may impact our business in multiple ways, including limiting our producers ability to finance their drilling programs and limiting our ability to grow our operations through acquisitions or organic growth projects. These events may impact our counterparties ability to perform under their credit or commercial obligations. While we did not experience significant collection issues during 2008, we continue to monitor the payment patterns of our customers. Where possible, we have obtained additional collateral agreements, letters of credit from highly rated banks, or have managed credit lines. To date, our counterparties to our existing derivative instruments have fully performed under their commitments. Due to the bankruptcy of Lehman Brothers Commercial Bank, or Lehman Brothers, a lender to our Credit Agreement, the availability of borrowings under this facility has been reduced by approximately $25.4 million. Accordingly, the capacity under our Credit Agreement is approximately $824.6 million, excluding Lehman Brothers unfunded commitment.

Impact of Severe Weather

The economic impact of severe weather may negatively affect the nation s short-term energy supply and demand, and may result in increased commodity prices. Additionally, severe weather may restrict or prevent us from fully utilizing our assets, by damaging our assets, interrupting utilities, and through possible NGL and natural gas curtailments downstream of our facilities, which restricts our production. These impacts may linger past the time of the actual weather event. Severe weather may also impact the supply and demand in our wholesale propane business.

Other Factors

Natural Gas Services Segment

Our results of operations for our Natural Gas Services segment are impacted by (1) increases and decreases in the volume of natural gas that we gather and transport through our systems, which we refer to as throughput, (2) prices of commodities such as NGLs, crude oil and natural gas, (3) the operating efficiency of our processing facilities, and (4) potential limitations on throughput volumes arising from downstream and infrastructure capacity constraints. Throughput and operating efficiency generally are driven by wellhead production, plant recoveries, operating availability of our facilities, physical integrity and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate. Historical and current trends in the price changes of commodities may not be indicative of future trends. Throughput and prices are also driven by demand and take-away capacity for residue natural gas and NGLs.

Natural Gas Services segment results of operations 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 and cash flow. Our actual contract terms are based upon a variety of factors, including natural gas quality, geographic location, commodity 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, impacting our expansion in regions where certain types of contracts are more common and other market factors.

Additionally, our results of operations for our Natural Gas Services segment are impacted by market conditions causing variability in natural gas, crude oil and NGL prices. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally correlated to the price of crude oil, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close correlation. Changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary.

While pricing impacts the Natural Gas Services segment, we have mitigated a significant portion of the anticipated commodity price risk associated with the equity volumes from our gathering and processing operations, for both our consolidated entities and our proportionate share of exposure from our equity method investments, through 2013 with fixed price natural gas and crude oil swaps. We mark these derivative instruments to market through current period earnings based upon their fair value. While the swaps may mitigate the variability of our future cash flows resulting from changes in commodity prices, the mark-to-market method of accounting significantly increases the volatility of our net income because we recognize, in current period operating revenues, all non-cash gains and losses from the changes in the fair value of these derivatives. We primarily use crude oil swaps to mitigate our NGL and condensate commodity price risk. As a result, the volatility of our future cash flows and net income may increase if there is a change in the pricing relationship between crude oil and NGLs. We also continue to have price risk exposure related to the portion of our equity volumes that are not covered by these derivatives and we have financial risk exposure to the extent our actual equity volumes differ from our projections. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Commodity Cash Flow Protection Activities.

Based on historical trends, however, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather, and the domestic production and drilling activity level of exploration and production companies. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity in the future. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall below demand levels.

Wholesale Propane Logistics Segment

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. We may mitigate a portion of the anticipated commodity price risk associated with fixed price propane sales by entering into either offsetting physical purchase agreements or financial derivative instruments, with DCP Midstream, LLC or third parties, which typically match the quantities of propane subject to these fixed price sales agreements. There may be an impact on sales volumes from weather conditions in the midwest and northeastern areas of the United States. Our annual sales volumes of propane may decline when these areas experience periods of milder weather in the winter months. Volumes may also be impacted by conservation and reduced demand in the current recessionary environment.

NGL Logistics Segment

Our results of operations for our NGL Logistics segment are impacted by the throughput volumes of the NGLs we transport on our NGL pipelines, as we transport NGLs exclusively on a fee basis. Throughput may be negatively impacted as a result of our customers operating their processing plants in ethane rejection mode, often as a result of low commodity prices for ethane. During the fourth quarter of 2008, we did experience reduced throughput due to ethane rejection at certain plants. Factors that impact the supply and demand of NGLs, as described above in our Natural Gas Services segment, may also impact the throughput for our NGL Logistics segment.

Other

The above factors, including further sustained deterioration in commodity prices, volumes or other market declines, including a decline in our unit price, may negatively impact our results of operations, and may increase the likelihood of a non-cash impairment charge or non-cash lower of cost or market inventory adjustments.

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.

Commodity Prices In the fourth quarter of 2008, natural gas, NGL and crude oil prices dropped significantly compared to prices in 2007 and the first three quarters of 2008. We are continuing to experience relatively lower commodity prices in 2009. Commodity prices are impacted by demand, which has been negatively impacted by the current recessionary environment.

Natural Gas Supply and Outlook In the near term, softening of natural gas prices, reduced demand for natural gas and NGLs, potential reduction in available capital, and the recent downturn in the economy have had a moderating effect on levels of drilling activity. The impact of these factors will vary across our broad geographic locations. Generally, we expect a decrease in drilling levels in 2009. The number of active oil and gas rigs drilling in the United States was 364 and 1,347, respectively, at December 31, 2008, compared to 325 and 1,452, respectively, at December 31, 2007. Our long-term view is that natural gas prices will return to a level that would support the relatively higher levels of natural gas-related drilling experienced in recent years in the United States, as producers seek to increase their level of natural gas production. We believe that in the long-term an increase in United States drilling activity, additional sources of supply such as liquefied natural gas, and imports of natural gas will be required for the natural gas industry to meet the expected increased demand for natural gas in the United States.

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Additionally, the capacity on certain downstream NGL and natural gas infrastructure has tightened recently and can be further constrained seasonally or when there is severe weather. Constrained market outlets may restrict us from operating our facilities optimally.

Processing Margins Except for our fee-based contracts, 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 cash flow exposure to commodity price movements for these commodities by entering into derivative arrangements through 2013 for a significant portion of our currently anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Commodity Cash Flow Protection Activities.

Wholesale Propane Supply and Outlook We are a wholesale supplier of propane for the midwest and northeastern United States, which consists of Connecticut, Maine, Massachusetts, New Hampshire, New York, Ohio, Pennsylvania, Rhode Island and Vermont. 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 supplies of propane during periods of tight supply, such as the winter months when their retail customers consume the most propane for home heating.

Competition The natural gas services business is highly competitive in our markets and includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or natural gas liquids. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter in length of term and therefore must be renegotiated on a more frequent basis.

The wholesale propane business is highly competitive in the upper midwest and northeastern regions of the United States. Our wholesale propane business competitors include major integrated oil and gas and energy companies, and interstate and intrastate pipelines.

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. Recently however, we have seen softening in certain costs. In the future, we may again 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.

2009 Outlook

Our focus in 2009 will be on the basics of the business, including operating our assets well, being disciplined with all uses of funds and effectively managing our business risk and daily operations in a very uncertain and volatile business environment.

The restoration of our operations is nearing completion. Repairs to the Discovery system, which was damaged by the hurricanes in fall 2008, were substantially completed in January 2009. Approximately 85% of the volumes and margins have been returned to service, with the remainder expected by early March. The Discovery distribution is paid one quarter in arrears. We do not expect to receive a distribution from Discovery during the first quarter of 2009.

We would expect to receive a distribution during the second quarter of 2009, commensurate with the partial restoration in January 2009, and a distribution during the third quarter of 2009, commensurate with the return to full service. The second phase of our Douglas pipeline integrity and system enhancement project has been completed, returning over 80% of the system volumes to service by mid-January 2009. The final phase is on target for completion in March 2009.

We are in the process of returning gas online following the fire caused by a third party pipeline rupture near our Carthage Hub, and expect it to be returned to normal service by the end of March 2009.

We will continue to execute on our two organic growth projects in the Piceance Basin and East Texas. We expect the remaining spending to be approximately $65.0 million in 2009, which will be funded through our existing credit facility.

We expect to close the transaction with DCP Midstream, LLC in April 2009 to acquire an additional 25.1% interest in East Texas. We expect the transaction will be fully financed through the issuance of 3.5 million Class D units issued to DCP Midstream, LLC. The transaction is expected to generate cash flow from operations of approximately $15.0 million over the first twelve month period following the close of the transaction. As a part of the transaction, DCP Midstream, LLC is expected to provide a fixed price NGL derivative by component for the first twelve month period following the close of the transaction.

Cash flow assumptions for our 2009 outlook include a full year impact from our Michigan acquisition, an increase in cash flows during the second half of the year related to our Piceance Basin and East Texas capital projects, and maintenance capital of $10.0 million to $15.0 million, which includes the remaining spending for the Douglas pipeline integrity and system enhancement project. In total, we estimate the impact to cash flow in 2009 as a result of operations disruptions at Discovery and Douglas to be approximately $10.0 million to $12.0 million.

Our cash flows are expected to vary under various commodity price scenarios. However, the combination of our significant fee-based business, our highly hedged position and minimum fees in certain contracts provide downside protection to our cash flows.

Our percentage of fee-based margins is expected to be approximately 56% in 2009. We have hedged approximately 80% of our equity position in natural gas liquids, condensate and natural gas associated with the remainder of our expected margins that are not fee-based.

Based upon our business plan, we expect that our available capacity under our existing credit facility is sufficient to support our operating needs and capital program in 2009.

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 from contracts that contain a combination 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. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.

Percent-of-proceeds Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and

NGLs based on index prices from 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. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percent-of-proceeds arrangements correlate directly with the price of natural gas and/or NGLs.

In addition to the above contract types, our equity method investments also generate equity earnings for our Natural Gas Services segment under keep-whole arrangements. Under the terms of a keep-whole processing contract, we gather natural gas from the producer for processing, sell the NGLs and return to the producer residue natural gas with a Btu content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under this type of contract, we are exposed to the frac spread. The frac spread is the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL prices are higher relative to natural gas prices when that frac spread exceeds the operating costs of our equity method investments. Fluctuations in commodity prices are expected to continue to impact the operating costs of these entities.

We have mitigated a significant portion of our anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with fixed price natural gas and crude oil swaps. With these swaps, we expect our cash flow exposure to commodity price movements to be reduced. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Commodity Cash Flow Protection Activities.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We are using the mark-to-market method of accounting for all commodity derivative financial instruments, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on non-trading derivative activity.

The natural gas supply for our gathering pipelines and processing plants is derived primarily from natural gas wells located in Colorado, Louisiana, Michigan, Oklahoma, Texas, Wyoming and the Gulf of Mexico. The Pelico system also receives natural gas produced in Texas through its interconnect with other pipelines that transport natural gas from Texas into western Louisiana. These areas have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. Our two primary suppliers of natural gas in our Natural Gas Services segment represented approximately 30% of the 499 MMcf/d of natural gas supplied to this system in 2008. 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 directly received or released from other gathering systems.

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. We typically sell natural gas under market index related pricing terms. The NGLs extracted from the natural gas at our processing plants are sold at market index prices to DCP Midstream, LLC or its affiliates, or to third parties. In addition, under our merchant arrangements, we use a subsidiary of 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 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 may 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.

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 identify primary suppliers as those individually representing 10% or more of our total propane supply. Our three primary suppliers of propane, two of which are affiliated entities, represented approximately 82% of our propane supplied in 2008. 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, annual and 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 supplies of propane during periods of tight supply, such as the winter months when their retail customers generally 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 generally significantly greater than their purchase of propane from us in the summer. We believe these factors generally allow us to maintain our generally 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 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 typically 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. Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may continue to periodically recognize non-cash lower of cost or market inventory adjustments. In addition, we may use financial derivatives to manage the value of our propane inventories.

NGL Logistics Segment

Our pipelines provide transportation services for customers on a fee basis. We have entered into contractual arrangements with DCP Midstream, LLC that require DCP Midstream, LLC to pay us to transport NGLs pursuant to a fee-based rate that is applied to the volumes transported. Therefore, the results of operations for this business segment 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 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, segment gross margin and adjusted segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) EBITDA and adjusted EBITDA; and (5) distributable cash flow. Gross margin, segment gross margin, adjusted segment gross margin, EBITDA, adjusted EBITDA and distributable cash flow measurements are not GAAP financial measures. We provide reconciliations of certain non-GAAP measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

Volumes We view throughput volumes for our Natural Gas Services segment and our NGL Logistics segment, and sales volumes for our Wholesale Propane Logistics segment as important factors 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 our 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 our NGL pipelines. We regularly monitor producer activity in the areas we serve and our pipelines, and pursue opportunities to connect new supply to these pipelines.

Gross Margin, Segment Gross Margin and Adjusted Segment 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. We define adjusted segment gross margin as segment gross margin plus non-cash derivative losses, less non-cash derivative gains for that segment. Gross margin, segment gross margin and adjusted segment gross margin are primary performance measures used by management, as these measures represent the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin, segment gross margin and adjusted segment gross margin should not be considered an alternative to, or more meaningful than, net income or loss, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

Our gross margin, segment gross margin and adjusted segment gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner. The following table sets forth our reconciliation of certain non-GAAP measures:

Reconciliation of Non-GAAP Measures	**Year Ended December 31, 2008**	**2007**	**2006**
		(Millions)	
Reconciliation of net income (loss) to gross margin:			
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Interest expense	32.8	25.8	11.5
Income tax expense	0.1	0.1	
Operating and maintenance expense	43.0	32.1	23.7
Depreciation and amortization expense	36.5	24.4	12.8
General and administrative expense	24.0	24.1	21.0
Other	(1.5)		
Non-controlling interest in income	3.9	0.5	
Interest income	(5.6)	(5.3)	(6.3)
Earnings from equity method investments	(34.3)	(39.3)	(29.2)
Gross margin	$ 224.6	$ 46.6	$ 95.4
Reconciliation of segment net income to segment gross margin:			
Natural Gas Services segment:			
Segment net income	$ 170.2	$ 11.6	$ 79.6
Depreciation and amortization expense	33.8	21.9	11.1
Operating and maintenance expense	32.1	20.9	13.5
Non-controlling interest in income	3.9	0.5	
Earnings from equity method investments	(33.5)	(38.7)	(28.9)
Segment gross margin	$ 206.5	$ 16.2	$ 75.3
Non-cash commodity derivative mark-to-market(a)	$ 99.2	$ (78.3)	$ 0.1
Wholesale Propane Logistics segment:			
Segment net income	$ 1.3	$ 14.0	$ 6.6
Depreciation and amortization expense	1.3	1.1	0.8
Operating and maintenance expense	9.9	10.4	8.6
Other	(1.5)		
Segment gross margin	$ 11.0	$ 25.5	$ 16.0
Non-cash commodity derivative mark-to-market(a)	$ 2.4	$ (2.8)	$
NGL Logistics segment:			
Segment net income	$ 5.5	$ 3.3	$ 1.9
Depreciation and amortization expense	1.4	1.4	0.9
Operating and maintenance expense	1.0	0.8	1.6

Earnings from equity method investments	(0.8)	(0.6)	(0.3)
Segment gross margin	$ 7.1	$ 4.9	$ 4.1

(a) Non-cash commodity derivative mark-to-market is included in segment gross margin, along with cash settlements for our derivative contracts.

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 depending on the activities performed during a specific period.

A substantial amount of our general and administrative expense is incurred from DCP Midstream, LLC. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, 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. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the acquisition of MPP. We also pay DCP Midstream, LLC an annual fee under the Omnibus Agreement 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, taxes and engineering. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, totaling $43.0 million at December 31, 2008, to certain counterparties to our commodity derivative instruments.

Our total general and administrative expense was comprised of the following:

	Year Ended December 31,		
	2008	**2007**	**2006**
Affiliate:			
Omnibus Agreement:			
Annual fee	$ 5.1	$ 5.0	$ 4.8
Wholesale propane logistics business	2.0	2.0	0.3
Southern Oklahoma	0.2	0.1	
Discovery	0.2	0.1	
Additional services	0.6	0.2	
Momentum Energy Group, Inc.	1.6	0.5	
Michigan Pipeline & Processing, LLC	0.1		
Total Omnibus Agreement	9.8	7.9	5.1
Other DCP Midstream, LLC	1.8	2.1	3.0
Total affiliate	11.6	10.0	8.1
Other	12.4	14.1	12.9
Total	$ 24.0	$ 24.1	$ 21.0

Following is a summary of the fees we anticipate incurring in 2009 under the Omnibus Agreement and the effective date for these fees:

Terms	**Effective Date**	**Fee**

		(Millions)
Annual fee	2006	$ 5.1
Wholesale propane logistics business	November 2006	2.0
Southern Oklahoma	May 2007	0.2
Discovery	July 2007	0.2
Additional services	August 2007	0.6
Momentum Energy Group, Inc.	August 2007	1.6
Michigan Pipeline & Processing, LLC	October 2008	0.4
Total		$ 10.1

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The Omnibus Agreement also addresses the following matters:

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 for certain obligations related to derivative financial instruments, such as commodity derivative instruments, to the extent that such credit support arrangements were in effect as of December 7, 2005 until the earlier of December 7, 2010 or when we obtain certain credit ratings 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 for our obligations related to commercial contracts with respect to its business or operations that were in effect at December 7, 2005 until the expiration of such contracts.

All of the fees under the Omnibus Agreement will be adjusted annually by the percentage change 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.

Other general and administrative expenses paid to DCP Midstream, LLC subsequent to our initial public offering include labor and benefit costs related to accounting and internal audit personnel, insurance as well as other administrative costs. Additionally, 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 investments, 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.

We also incurred third party general and administrative expenses, which were primarily related 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.

EBITDA, Adjusted EBITDA and Distributable Cash Flow We define EBITDA as net income or loss less interest income, plus interest expense, income tax expense and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus non-cash commodity derivative losses, less non-cash commodity derivative gains. EBITDA and adjusted EBITDA are used as supplemental liquidity and performance measures 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;

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.

Our EBITDA and adjusted EBITDA may not be comparable to similarly titled measures of another company because other entities may not calculate these measures in the same manner. As discussed in the Liquidity and Capital Resources section below, our credit facility also defines EBITDA, which is used in evaluating our compliance with our financial covenants.

EBITDA and adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, 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. The following table sets forth reconciliations of EBITDA from its most directly comparable financial measures calculated in accordance with GAAP:

	Year Ended December 31,		
Reconciliation of Non-GAAP Measures	**2008**	**2007**	**2006**
		(Millions)	
Reconciliation of net income (loss) to EBITDA:			
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Interest income	(5.6)	(5.3)	(6.3)
Interest expense	32.8	25.8	11.5
Income tax expense	0.1	0.1	
Depreciation and amortization expense	36.5	24.4	12.8
EBITDA	$ 189.5	$ 29.2	$ 79.9
Reconciliation of net cash provided by operating activities to EBITDA:			
Net cash provided by operating activities	$ 101.5	$ 65.4	$ 94.8
Interest income	(5.6)	(5.3)	(6.3)
Interest expense	32.8	25.8	11.5
Earnings from equity method investments, net of distributions	(25.6)	0.4	3.3
Income tax expense	0.1	0.1	
Net changes in operating assets and liabilities	89.8	(56.9)	(25.8)
Other, net	(3.5)	(0.3)	2.4
EBITDA	$ 189.5	$ 29.2	$ 79.9

We define distributable cash flow as net cash provided by or used in operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, proceeds from divestiture of assets, non-controlling interest on depreciation, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities (see Liquidity and Capital Resources for further definition of maintenance capital expenditures). Maintenance capital expenditures are capital expenditures made 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. Non-cash mark-to-market of derivative instruments 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 liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner. Our distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate distributable cash flow in the same manner.

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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. These accounting policies are described further in Note 2 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Inventories		
Inventories, which consist primarily of propane, are recorded at the lower of weighted-average cost or market value.	Judgment is required in determining the market value of inventory, as the geographic location impacts market prices, and quoted market prices may not be available for the particular location of our inventory.	If the market value of our inventory is lower than the cost, we may be exposed to losses that could be material. If propane prices were to decrease by 10% below our December 31, 2008 weighted-average cost, our net income would be affected by approximately $2.1 million.
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.	We determine fair value using widely accepted valuation techniques, namely discounted cash flow and market multiple analyses. These techniques are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.	We completed our impairment testing of goodwill using the methodology described herein, and determined there was no impairment. We have not recorded goodwill impairment during the year ended December 31, 2008. The carrying value of goodwill as of December 31, 2008 was $88.8 million.
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 expected to be realized over the remaining useful life of the	Our impairment analyses may require management to apply judgment in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows.	Using the impairment review methodology described herein, we have not recorded impairment charges during the year ended December 31, 2008. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an

primary asset. The carrying amount is not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. 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 and discounted cash flow models. These techniques are also used when allocating the purchase price to acquired assets and liabilities.

impairment charge. The carrying value of our long-lived assets as of December 31, 2008 was $677.0 million.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
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 a 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.	Our impairment loss calculations require management to apply judgment in estimating future cash flows and asset fair values, including forecasting useful lives of the assets, assessing the probability of differing estimated outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. 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 and discounted cash flow models.	Using the impairment review methodology described herein, we have not recorded impairment charges during the year ended December 31, 2008. If the estimated fair value of our equity method investments is less than the carrying value, we would recognize an impairment loss for the excess of the carrying value over the estimated fair value. The carrying value of our equity method investments as of December 31, 2008 was $175.4 million.
Accounting for Risk Management Activities and Financial Instruments		
Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on derivative instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments at fair value until the contractual settlement period impacts earnings. 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.	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.	If our estimates of fair value are inaccurate, we may be exposed to losses or gains that could be material. A 10% difference in our estimated fair value of derivatives at December 31, 2008 would have affected net income by approximately $2.0 million for the year ended December 31, 2008.
Accounting for Equity-Based Compensation		
Our long-term incentive plan permits for the grant of restricted units, phantom units, unit options and substitute awards. Equity-based compensation expense is recognized	Estimating the fair value of each award, the number of awards that will ultimately vest, and the forfeiture rate requires management to apply judgment to estimate the	If actual results are not consistent with our assumptions and judgments or our assumptions and estimates change due to new information, we may experience material changes in

over the vesting period or service 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 period.	tenure of our employees and the achievement of certain performance targets over the performance period.	compensation expense.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Accounting for Asset Retirement Obligations		
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 is determined using a credit adjusted risk free interest rate, and increases due to the passage of time based on the time value of money until the obligation is settled.	Estimating the fair value of asset retirement obligations requires management to apply judgment to evaluate the necessary retirement activities, estimate the costs to perform those activities, including the timing and duration of potential future retirement activities, and estimate the risk free interest rate. When making these assumptions, we consider a number of factors, including historical retirement costs, the location and complexity of the asset and general economic conditions.	If actual results are not consistent with our assumptions and judgments or our assumptions and estimates change due to new information, we may experience material changes in our asset retirement obligations. Establishing an asset retirement obligation has no initial impact on net income. A 10% change in depreciation and accretion expense associated with our asset retirement obligations during the year ended December 31, 2008, would not have had a significant effect on net income.

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, 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2007 vs. 2006	
	2008(a)	2007(a)	2006	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)						
Operating revenues:							
Natural Gas Services(b)	$ 791.5	$ 404.1	$ 415.3	$ 387.4	96%	$ (11.2)	(3)%
Wholesale Propane Logistics	483.0	459.6	375.2	23.4	5%	84.4	23%
NGL Logistics	11.3	9.6	5.3	1.7	18%	4.3	81%
Total operating revenues	1,285.8	873.3	795.8	412.5	47%	77.5	10%
Gross margin(c):							
Natural Gas Services	206.5	16.2	75.3	190.3	1,175%	(59.1)	(78)%
Wholesale Propane Logistics	11.0	25.5	16.0	(14.5)	(57)%	9.5	59%
NGL Logistics	7.1	4.9	4.1	2.2	45%	0.8	20%
Total gross margin	224.6	46.6	95.4	178.0	382%	(48.8)	(51)%
Operating and maintenance expense	(43.0)	(32.1)	(23.7)	10.9	34%	8.4	35%
General and administrative expense	(24.0)	(24.1)	(21.0)	(0.1)	%	3.1	15%
Other	1.5			1.5	*		%
Earnings from equity method investments(d)	34.3	39.3	29.2	(5.0)	(13)%	10.1	35%
Non-controlling interest in income	(3.9)	(0.5)		3.4	680%	0.5	100
EBITDA(e)	189.5	29.2	79.9	160.3	549%	(50.7)	(64)%
Depreciation and amortization expense	(36.5)	(24.4)	(12.8)	12.1	50%	11.6	91%
Interest income	5.6	5.3	6.3	0.3	6%	(1.0)	16%
Interest expense	(32.8)	(25.8)	(11.5)	7.0	27%	14.3	*
Income tax expense	(0.1)	(0.1)			%	0.1	100%
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9	$ 141.5	*	$ (77.7)	*

Operating data:							
Natural gas throughput (MMcf/d)(d)	838	756	666	82	11%	90	14%
NGL gross production (Bbls/d)(d)	20,659	22,122	19,485	(1,463)	(7)%	2,637	14%
Propane sales volume (Bbls/d)	21,053	22,798	21,259	(1,745)	(8)%	1,539	7%
NGL pipelines throughput (Bbls/d)(d)	31,407	28,961	25,040	2,446	8%	3,921	16%

* Percentage change is not meaningful.

(a) Includes the results from the Michigan Pipeline & Processing, LLC, or MPP, Momentum Energy Group, Inc, or MEG, and Southern Oklahoma acquisitions, from their respective acquisition dates of October 2008, August 2007 and May 2007.

(b) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap was for a total of approximately 1.9 million barrels at $66.72 per barrel.

(c) Gross margin consists of total operating revenues, including commodity derivative activity, 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.

(d) Includes our proportionate share of the throughput volumes and earnings of Black Lake, East Texas and Discovery for all periods presented. Earnings for Discovery and Black Lake include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the investments.

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

Year Ended December 31, 2008 vs. Year Ended December 31, 2007

Total Operating Revenues Total operating revenues increased in 2008 compared to 2007, primarily due to the following:

$213.7 million increase primarily attributable to increased commodity prices as well as higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions, partially offset by decreased volumes due to the impact of hurricanes, for our Natural Gas Services segment;

$156.8 million increase related to commodity derivative activity, resulting from the following:

we had a gain of $72.3 million in 2008 and a loss of $87.6 million in 2007, resulting in an increase of $159.9 million, which is included in gains (losses) from commodity derivative activity. This increase includes an increase in unrealized gains of $184.1 million due to forward prices of commodities generally being lower at the end of the year 2008 compared to 2007. Offsetting this increase in gain was an increase in realized cash settlement losses of $24.2 million due to average prices of commodities generally being higher for the year ended December 31, 2008 compared to 2007; and

we had a $3.1 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate;

$22.1 million increase in transportation processing and other revenue, primarily attributable to the MEG and MPP acquisitions in our Natural Gas Services segment;

$19.0 million increase attributable to higher propane prices offset by decreased propane sales volumes as a result of lower demand for our Wholesale Propane Logistics segment; and

$0.9 million increase due to increased throughput volumes, transportation, processing and other revenue, and increases related to settlement of pipeline imbalances in our NGL logistics segment.

Gross Margin Gross margin increased in 2008 compared to 2007, primarily due to the following:

$190.3 million increase for our Natural Gas Services segment primarily due to increases related to commodity derivative activity, an increase in natural gas, NGL and condensate production, mainly as a result of the MEG, MPP and Southern Oklahoma acquisitions, partially offset by decreased volumes due to the impact of hurricanes; and

$2.2 million increase for our NGL Logistics segment primarily attributable to increases related to settlement of pipeline imbalances and increased throughput volumes; partially offset by

$14.5 million decrease for our Wholesale Propane Logistics segment as a result of increased non-cash lower of cost or market inventory adjustments due to a decline in propane prices in the second half of 2008. We estimate that approximately half of the 2008 write downs were recovered through the sale of inventory in 2008. We also had lower per unit margins and propane sales volumes, partially offset by commodity derivative activity.

Operating and Maintenance Expense Operating and maintenance expense increased in 2008 compared to 2007, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions in our Natural Gas Services segment, partially offset by decreased property taxes in our Wholesale Propane Logistics segment.

General and Administrative Expense General and administrative expense decreased in 2008 compared to 2007, primarily due to acquisition-related costs incurred in 2007 and decreased compensation and benefits in 2008, partially offset by increased legal expenses in 2008.

Earnings from Equity Method Investments Earnings from equity method investments decreased in 2008 compared to 2007, primarily due to decreased equity earnings of $6.7 million from Discovery due primarily to hurricanes, as discussed in the Natural Gas Services Segment section below, partially offset by increased equity earnings of $1.5 million from East Texas and $0.2 million from Black Lake.

Non-Controlling Interest in Income Non-controlling interest in income reduced income by $3.9 million and $0.5 million in 2008 and 2007, respectively, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition and in 2008 also includes the non-controlling interest holders portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2008 compared to 2007, primarily as a result of acquisitions.

Interest Expense Interest expense increased in 2008 compared to 2007, primarily as a result of financing acquisitions, partially offset by lower average interest rates.

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

Total Operating Revenues Total operating revenues increased in 2007 compared to 2006, primarily due to the following:

$88.1 million increase attributable to higher propane prices and higher sales volumes for our Wholesale Propane Logistics segment;

$66.2 million increase primarily attributable to an increase in natural gas, NGL and condensate sales volumes, including increases as a result of the MEG and Southern Oklahoma acquisitions, and increases in NGL and condensate prices, partially offset by a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation for our Natural Gas Services segment;

$7.3 million increase in transportation processing and other revenue primarily attributable to an increase in throughput volumes in our Natural Gas Services segment; and

$3.4 million increase due to changes in product mix and increased volumes for our NGL Logistics segment; offset by

$87.5 million decrease related to commodity derivative activity, an increase of $0.2 million which is included in sales of natural gas, NGLs and condensate, and a decrease of $87.7 million which is included in losses from derivative activity.

Gross Margin Gross margin decreased in 2007 compared to 2006, primarily due to the following:

$59.1 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity derivative activity, and a decrease in marketing margins from the decline in the differences of natural gas prices at various receipt and delivery points across our Pelico system, offset by an increase in NGL and condensate production, mainly as a result of the MEG and Southern Oklahoma acquisitions, an increase in natural gas throughput volumes and higher contractual fees charged to customers; offset by

$9.5 million increase for our Wholesale Propane Logistics segment due to higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, decreased non-cash lower of cost or market inventory adjustments recognized in 2007, and higher sales volumes primarily due to the completion of the Midland terminal, which became operational in May 2007, partially offset by a decrease related to commodity derivative activity; and

$0.8 million increase for our NGL Logistics segment primarily attributable to changes in product mix and increased volumes, as well as increased transportation processing and other revenue.

Operating and Maintenance Expense Operating and maintenance expense increased in 2007 compared to 2006, primarily as a result of the MEG and Southern Oklahoma acquisitions, higher labor and benefits and pipeline integrity costs in our Natural Gas Services segment, and higher operating and maintenance expense at the Midland terminal, which became operational in May 2007 in our Wholesale Propane Logistics segment, offset by lower pipeline integrity costs on our Seabreeze pipeline in our NGL Logistics segment.

General and Administrative Expense General and administrative expense increased in 2007 compared to 2006, primarily as a result of increased due diligence and acquisition costs, increased fees under our omnibus agreement with DCP Midstream, LLC and increased labor and benefit costs, partially offset by decreases in audit and public company costs.

Earnings from Equity Method Investments Earnings from equity method investments increased in 2007 compared to 2006, primarily due to increased equity earnings of $7.2 million from Discovery, $2.6 million from East Texas and $0.3 million from Black Lake.

Non-Controlling Interest in Income Non-controlling interest in income reduced income by $0.5 million in 2007, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2007 compared to 2006, primarily as a result of acquisitions.

Interest Expense Interest expense increased in 2007 compared to 2006, primarily as a result of financing the 2007 acquisitions.

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Results of Operations Natural Gas Services Segment

This segment consists of our Northern Louisiana system, the Southern Oklahoma system acquired in May 2007, a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, and the Swap, acquired in July 2007, our Colorado and Wyoming systems, acquired in August 2007 and our Michigan systems, acquired in October 2008.

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2007 vs. 2006	
	2008(a)	2007(a)	2006	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of natural gas, NGLs and condensate	$ 668.8	$ 458.2	$ 391.8	$ 210.6	46%	$ 66.4	17%
Transportation, processing and other	50.2	29.4	23.5	20.8	71%	5.9	25%
Gains (losses) from commodity derivative activity(b)	72.5	(83.5)		156.0	*	(83.5)	*
Total operating revenues	791.5	404.1	415.3	387.4	96%	(11.2)	(3)%
Purchases of natural gas and NGLs	585.0	387.9	340.0	197.1	51%	47.9	14%
Segment gross margin(c)	206.5	16.2	75.3	190.3	1,175%	(59.1)	(79)%
Operating and maintenance expense	(32.1)	(20.9)	(13.5)	11.2	54%	7.4	55%
Depreciation and amortization expense	(33.8)	(21.9)	(11.1)	11.9	54%	10.8	97%
Earnings from equity method investments(d)	33.5	38.7	28.9	(5.2)	(13)%	9.8	34%
Non-controlling interest in income	(3.9)	(0.5)		3.4	680%	0.5	100%
Segment net income	$ 170.2	$ 11.6	$ 79.6	$ 158.6	1,367%	$ (68.0)	(85)%
Operating data:							
Natural gas throughput (MMcf/d)(d)	838	756	666	82	11%	90	14%
NGL gross production (Bbls/d)	20,659	22,122	19,485	(1,463)	(7)%	2,637	14%

* Percentage change is not meaningful.

(a)

Includes the results from the MEG, MPP and Southern Oklahoma acquisitions, from their respective acquisition dates of October 2008, August 2007 and May 2007.

(b) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap was for a total of approximately 1.9 million barrels through 2012, at $66.72 per barrel.

(c) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read How We Evaluate Our Operations above.

(d) Includes our proportionate share of the throughput volumes and earnings of East Texas and Discovery for all periods presented. Earnings for Discovery include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the investments.

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Year Ended December 31, 2008 vs. Year Ended December 31, 2007

Total Operating Revenues Total operating revenues increased in 2008 compared to 2007, primarily due to the following:

$152.9 million increase related to commodity derivative activity, resulting from the following:

we had a gain of $72.5 million in 2008 and a loss of $83.5 million in 2007, resulting in an increase of $156.0 million, which is included gains (losses) from commodity derivative activity. This increase includes an increase in unrealized gains of $178.8 million due to forward prices of commodities generally being lower at the end of the year 2008 compared to 2007. Offsetting this increase in gain was an increase in realized cash settlement losses of $22.8 million due to average prices of commodities generally being higher for the year ended December 31, 2008 compared to 2007; and

we had a $3.1 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate;

$150.3 million increase attributable to increased commodity prices;

$63.4 million increase attributable to higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions, partially offset by decreased volumes due to the impact of hurricanes; and

$20.8 million increase in transportation, processing and other revenue as a result of the MEG and MPP acquisitions.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased in 2008 compared to 2007, primarily due to increased natural gas purchase volumes primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions, and higher costs of natural gas supply, driven by higher commodity prices.

Segment Gross Margin Segment gross margin increased in 2008 compared to 2007, primarily as a result of the following:

$152.9 million increase related to commodity derivative activity, as discussed in the Operating Revenues section above;

$24.1 million increase primarily attributable to an increase in natural gas, NGL and condensate production as a result of the MEG, MPP and Southern Oklahoma acquisitions, partially offset by decreased volumes due to the impact of hurricanes;

$9.0 million increase primarily attributable to changes in contract mix; and

$4.3 million increase due to higher commodity prices.

Operating and Maintenance Expense Operating and maintenance expense increased in 2008 compared to 2007, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2008 compared to 2007, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions.

Earnings from Equity Method Investments Earnings from equity method investments decreased in 2008 compared to 2007, primarily due to decreased equity earnings of $6.7 million from Discovery, partially offset by increased equity earnings of $1.5 million from East Texas. Decreased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery;

Decreased equity earnings from Discovery were the result of a decrease in Discovery s net income of $13.7 million due primarily to $32.5 million resulting from hurricanes Ike and Gustav, partially offset by $10.4 million higher product margins, $4.6 million lower depreciation and accretion expense and a 2008 reserve reversal of $3.5 million related to a recently approved Federal Energy Regulatory Commission rate case settlement.

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Increased equity earnings from East Texas were the result of an increase in East Texas s net income of $6.0 million due primarily to a $14.9 million increase as a result of higher commodity prices, a $9.0 million increase due to increased fee-based revenue, and decreased general and administrative expenses of $2.9 million, partially offset by a $12.9 million decrease due to decreased NGL production, partially due to the effects of hurricanes and other severe weather and an increase in operating and maintenance expenses of $7.3 million.

Non-Controlling Interest in Income Non-controlling interest in income reduced income by $3.9 million and $0.5 million in 2008 and 2007, respectively, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition and in 2008 also includes the non-controlling interest holders portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition.

Natural gas transported and/or processed increased in 2008 compared to 2007, due primarily to increased volumes from the MEG, MPP and Southern Oklahoma acquisitions and increased volumes from East Texas, partially offset by decreased volumes from Pelico and Discovery. NGL production decreased in 2008 compared to 2007, due primarily to decreased NGL production at Discovery as a result of the hurricanes.

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

Total Operating Revenues Total operating revenues decreased in 2007 compared to 2006, primarily due to the following:

$83.3 million decrease related to commodity derivative activity, an increase of $0.2 million which is included in sales of natural gas, NGLs and condensate, and a decrease of $83.5 million which is included in losses from derivative activity; offset by

$49.0 million increase attributable to an increase in natural gas, NGL and condensate sales volumes, primarily as a result of the MEG and Southern Oklahoma acquisitions, partially offset by a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation;

$17.2 million increase attributable to increased NGL and condensate prices; and

$5.9 million increase in transportation, processing and other services revenue primarily attributable to an increase in natural gas throughput.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased in 2007 compared to 2006, primarily due to increased natural gas purchase volumes primarily as a result of the MEG and Southern Oklahoma acquisitions, offset by decreased natural gas purchased volumes primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation.

Segment Gross Margin Segment gross margin decreased in 2007 compared to 2006, primarily as a result of the following:

$83.3 million decrease related to commodity derivative activity;

$2.5 million decrease attributable primarily to a decrease in marketing margins from the decline in the differences in natural gas prices at various receipt and delivery points across our Pelico system, which were atypically high in 2006; partially offset by

$25.2 million increase primarily attributable to an increase in NGL and condensate production, partially as a result of the MEG and Southern Oklahoma acquisitions, and an increase in natural gas throughput volumes;

$1.0 million increase primarily attributable to higher contractual fees charged to customers; and

$0.5 million increase primarily attributable to favorable frac spreads.

NGL production and natural gas transported and/or processed during 2007 increased compared to 2006. These increases were due primarily to increased volumes from Discovery, as well as an increase in volumes from the MEG and Southern Oklahoma acquisitions, partially offset by decreased volumes from Pelico.

Operating and Maintenance Expense Operating and maintenance expense increased in 2007 compared to 2006, primarily as a result of the MEG and Southern Oklahoma acquisitions, and higher labor and benefits and pipeline integrity costs.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2007 compared to 2006, primarily as a result of the MEG and Southern Oklahoma acquisitions.

Earnings from Equity Method Investments Earnings from equity method investments increased in 2007 compared to 2006, primarily due to increased equity earnings of $7.2 million from Discovery and $2.6 million from East Texas. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

Increased equity earnings from Discovery were the result of an increase in Discovery s net income of $18.0 million, or 60%, due primarily to $39.0 million higher gross processing margins resulting from higher NGL sales volumes and NGL prices, partially offset by $9.9 million lower fee-based transportation, gathering, processing and fractionation revenues, $5.9 million higher operating and maintenance expense and $2.2 million higher other expenses. In addition, exceptionally strong commodity margins compelled Discovery s customers to process their natural gas rather than by-pass, which led to higher product sales revenues on Discovery s percent-of-proceeds and keep-whole processing contracts.

Increased equity earnings from East Texas were the result of an increase in East Texas s net income of $10.7 million, or 22%, due primarily to a $28.5 million increase as a result of higher commodity prices and a $1.1 million decrease in income tax expense due to recording a deferred tax liability of $1.8 million in 2006 related to the Texas margin tax; partially offset by an $11.6 million decrease due to a decline in natural gas volumes, a $3.0 million decrease due to decreased fee-based revenue, and an increase in operating and maintenance expenses of $2.8 million, primarily due to increased contract services, materials and supplies, and labor an benefits, increased depreciation expense of $1.2 million due to the addition of a new pipeline, and increased general and administrative expenses of $0.6 million, primarily due to higher allocated costs from DCP Midstream, LLC.

Non-Controlling Interest in Income Non-controlling interest in income reduced income by $0.5 million in 2007, and represents the non-controlling interest holders portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

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Results of Operations Wholesale Propane Logistics Segment

This segment includes our propane transportation facilities, which includes six owned rail terminals, one of which was idled in 2007 to consolidate our operations, one leased marine terminal, one pipeline terminal and access to several open-access propane pipeline terminals.

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2007 vs. 2006	
	2008	2007	2006	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of propane	$ 482.1	$ 463.1	$ 375.0	$ 19.0	4%	$ 88.1	24%
Transportation, processing and other	1.1	0.6	0.1	0.5	83%	0.5	*
(Losses) gains from commodity derivative activity	(0.2)	(4.1)	0.1	(3.9)	(95)%	(4.2)	*
Total operating revenues	483.0	459.6	375.2	23.4	5%	84.4	23%
Purchases of propane	472.0	434.1	359.2	37.9	9%	74.9	21%
Segment gross margin(a)	11.0	25.5	16.0	(14.5)	(57)%	9.5	59%
Operating and maintenance expense	(9.9)	(10.4)	(8.6)	(0.5)	(5)%	1.8	21%
Depreciation and amortization expense	(1.3)	(1.1)	(0.8)	0.2	18%	0.3	38%
Other	1.5			1.5	*		%
Segment net income	$ 1.3	$ 14.0	$ 6.6	$ (12.7)	(91)%	$ 7.4	*
Operating Data:							
Propane sales volume (Bbls/d)	21,053	22,798	21,259	(1,745)	(8)%	1,539	7%

* Percentage change is not meaningful.

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

Year Ended December 31, 2008 vs. Year Ended December 31, 2007

Total Operating Revenues Total operating revenues increased in 2008 compared to 2007, primarily due to the following:

$54.1 million increase attributable to higher propane prices;

$3.9 million increase related to commodity derivative activity, which represents increased unrealized gains of $5.3 million, partially offset by increased realized cash settlement losses of $1.4 million; and

$0.5 million increase attributable to other fee revenue; partially offset by

$35.1 million decrease attributable to decreased propane sales volumes as a result of lower demand.

Purchases of Propane Purchases of propane increased in 2008 compared to 2007, primarily due to increased prices, partially offset by decreased purchased volumes.

Segment Gross Margin Segment gross margin decreased in 2008 compared to 2007, primarily as a result of increased non-cash lower of cost or market inventory adjustments of $15.1 million due to a decline in propane prices in the second half of 2008. We estimate that approximately half of the 2008 write downs were recovered through the sale of inventory in 2008. We also had lower per unit margins and lower propane sales volumes, partially offset by commodity derivative activity.

Propane sales volume decreased in 2008 compared to 2007, primarily as a result of lower demand.

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Operating and Maintenance Expense Operating and maintenance expense decreased in 2008 compared to 2007, primarily due to decreased property taxes.

Other Other operating income increased due to a payment received in the second quarter of 2008 from a supplier related to the early termination of its supply agreement.

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

Total Operating Revenues Total operating revenues increased in 2007 compared to 2006, primarily due to the following:

- $60.8 million increase attributable to higher propane prices;
- $27.3 million increase attributable to higher propane sales volumes as a result of colder weather in the northeastern United States and the completion of the Midland terminal, which became operational in May 2007; and
- $0.5 million increase in transportation, processing and other services; offset by
- $4.2 million decrease related to commodity derivative activity.

Purchases of Propane Purchases of propane increased in 2007 compared to 2006, primarily due to increased prices and purchased volumes, primarily due to colder weather in the northeastern United States and increased purchased volumes due to the completion of the Midland terminal, which became operational in May 2007, partially offset by decreased non-cash lower of cost or market inventory adjustments recognized in 2007.

Segment Gross Margin Segment gross margin increased in 2007 compared to 2006, primarily as a result of higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, decreased non-cash lower of cost or market inventory adjustments recognized in 2007, and higher sales volumes primarily due to the completion of the Midland terminal, which became operational in May 2007, partially offset by a decrease related to commodity derivative activity.

Propane sales volume increased in 2007 compared to 2006, due primarily to colder weather in the northeastern United States and the addition of the Midland terminal, which became operational in May 2007.

Operating and Maintenance Expense Operating and maintenance expense increased in 2007 compared to 2006, primarily due to operating and maintenance expense at the Midland terminal, which became operational in May 2007.

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Results of Operations NGL Logistics Segment

This segment includes our Seabreeze and Wilbreeze NGL transportation pipelines and our 45% interest in Black Lake.

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2007 vs. 2006	
	2008	2007	2006	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of NGLs	$ 5.4	$ 4.5	$ 1.1	$ 0.9	20%	$ 3.4	*
Transportation, processing and other	5.9	5.1	4.2	0.8	16%	0.9	21%
Total operating revenues	11.3	9.6	5.3	1.7	18%	4.3	81%
Purchases of NGLs	4.2	4.7	1.2	(0.5)	(11)%	3.5	*
Segment gross margin(a)	7.1	4.9	4.1	2.2	45%	0.8	20%
Operating and maintenance expense	(1.0)	(0.8)	(1.6)	0.2	25%	(0.8)	(50)%
Depreciation and amortization expense	(1.4)	(1.4)	(0.9)		%	0.5	56%
Earnings from equity method investment(b)	0.8	0.6	0.3	0.2	33%	0.3	100%
Segment net income	$ 5.5	$ 3.3	$ 1.9	$ 2.2	67%	$ 1.4	74%
Operating data:							
NGL pipelines throughput (Bbls/d)(b)	31,407	28,961	25,040	2,446	8%	3,921	16%

* Percentage change is not meaningful.

(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 our proportionate share of the throughput volumes and earnings of Black Lake for all periods presented. Earnings for Black Lake include the amortization of the net difference between the carrying amount of the investment and the underlying equity of the investment.

Year Ended December 31, 2008 vs. Year Ended December 31, 2007

Total Operating Revenues Total operating revenues increased in 2008 compared to 2007, primarily due to increased throughput volumes, increased transportation, processing and other revenue, and increases related to settlement of pipeline imbalances.

Purchases of NGLs Purchases of NGLs decreased in 2008 compared to 2007, due to settlement of pipeline imbalances, partially offset by increased throughput volumes.

Segment Gross Margin Segment gross margin increased in 2008 compared to 2007, primarily due to increases related to settlement of pipeline imbalances and increased throughput volumes.

Overall, our NGL pipelines experienced an increase in throughput volumes in 2008 as compared to 2007, primarily as a result of an increase in processing activity associated with increased drilling due to higher commodity prices.

Earnings from Equity Method Investments Earnings from equity method investments increased in 2008 compared to 2007, due to increased throughput volumes resulting in higher Black Lake equity earnings.

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

Total Operating Revenues Total operating revenues increased in 2007 compared to 2006, primarily due to changes in product mix and increased volumes, as well as increased transportation, processing and other revenue. Increased volumes and transportation, processing and other revenue are primarily as a result of the addition of our Wilbreeze pipeline in December 2006.

Purchases of NGLs Purchases of NGLs increased in 2007 compared to 2006, primarily due to changes in product mix and increased volumes.

Segment Gross Margin Segment gross margin increased in 2007 compared to 2006, primarily due to changes in product mix and increased volumes, as well as increased transportation, processing and other revenue.

Overall, our NGL pipelines experienced an increase in throughput volumes during 2007 as compared to 2006, primarily as a result of the addition of our Wilbreeze pipeline.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2007 compared to 2006, primarily due to lower pipeline integrity costs on our Seabreeze pipeline.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2007 compared to 2006, primarily as a result of the addition of our Wilbreeze pipeline.

Earnings from Equity Method Investments Earnings from equity method investments increased in 2007 compared to 2006, due to higher Black Lake revenues, partially offset by increased project costs.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our equity method investments;
- 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;
- debt offerings;
- guarantees issued by DCP Midstream, LLC, which reduce the amount of collateral we may be required to post with certain counterparties to our commodity derivative instruments; and
- letters of credit.

We anticipate our more significant uses of resources to include:

- capital expenditures;
- contributions to our equity method investments to finance our share of their capital expenditures;
- business and asset acquisitions;
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts, which may, at times, be significant depending on commodity price movements, and which is required to the extent we

exceed certain guarantees issued by DCP Midstream, LLC and letters of credit we have posted; 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 for the next twelve months. In the event these sources are not sufficient, we would reduce our discretionary spending, which may include capital spending.

Beginning in the third quarter of 2008, the capital markets experienced volatility, uncertainty and interventions by various governments around the globe. The effects of these market conditions include significant changes in the valuation of equity securities and overnight and longer-term borrowing rates. The availability of credit through traditional sources of funding such as the commercial paper, bank lending and the private and public placement debt markets also decreased dramatically. In these market conditions, it is uncertain if we would be successful in obtaining timely additional funding from the traditional equity or debt markets if it were needed. Furthermore, the cost of such new funding could substantially exceed the cost of funds previously obtained. Based on current and anticipated levels of operations, we believe we have adequate committed financial resources to conduct our business, although deterioration in our operating environment beyond that currently anticipated could limit our borrowing capacity as well as impact our compliance with the Credit Agreement s financial covenant requirements.

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 mitigated a significant portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with fixed price natural gas and crude oil swaps. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Commodity Cash Flow Protection Activities.

Our banking group is comprised of various financial institutions, of which certain institutions have recently merged. We do not expect the aggregate contractual financial commitment of these institutions to us to change during the remaining life of our existing credit agreement as a result of these mergers.

The capacity under our Credit Agreement is approximately $824.6 million, net of Lehman Brothers unfunded commitment. Our borrowing capacity may be limited by the Credit Agreement s financial covenant requirements. Except in the case of a default, which would make the borrowings under the Credit Agreement fully callable, amounts borrowed under our Credit Agreement will not mature prior to the June 21, 2012 maturity date. As of February 23, 2009, we had approximately $228.0 million of net available borrowings under our Credit Agreement.

Certain of our counterparties are experiencing financial difficulties, which did not have a significant impact on our business in 2008.

The counterparties to each of our commodity swap contracts 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. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty s assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. As of February 23, 2009, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $83.0 million to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with these counterparties. Prior to our initial public offering, DCP Midstream, LLC provided parental guarantees to certain counterparties to our commodity derivative instruments, totaling $43.0 million as of February 23, 2009. In July 2008, DCP Midstream, LLC provided additional parental guarantees to certain counterparties to our commodity derivative instruments, totaling $40.0 million as of February 23, 2009. We pay DCP Midstream, LLC a fee of 0.5% per annum on $40.0 million of these guarantees. The fee on the remaining guarantees is covered under the omnibus agreement with DCP Midstream, LLC. As of February 23, 2009, we had a letter of credit of $10.0 million. These parental guarantees and letter of credit reduce the amount of cash we may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under our credit facility. As of February 23, 2009, we had no cash collateral posted with counterparties. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. Predetermined collateral thresholds for commodity derivative instruments guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC s credit rating and the thresholds would be reduced to $0 in the event DCP Midstream, LLC s credit rating were to fall below investment grade.

Discovery is owned 40% by us and 60% by Williams Partners, LP. Discovery is managed by a two-member management committee, consisting of one representative from each owner. The members of the management committee have voting power corresponding to their respective ownership interests in Discovery. All actions and decisions relating to Discovery require the unanimous approval of the owners except for a few limited situations. Discovery must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval, will determine the amount of the distributions. In addition, the owners are required to offer to Discovery all opportunities to construct pipeline laterals within an area of interest. Calls for capital contributions are determined by a vote of the management committee and require unanimous approval of both owners in most instances.

East Texas is owned 25% by us and 75% by DCP Midstream, LLC. East Texas is managed by a four-member management committee, consisting of two representatives from each owner. The members of the management committee have voting power corresponding to their respective ownership interests in East Texas. Most significant actions relating to East Texas require the unanimous approval of both owners. East Texas must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval, will determine the amount of the distributions. Calls for capital contributions are determined by a vote of the management committee and require unanimous approval of both owners except in certain situations, such as the breach or default of a material agreement or payment obligation, that are reasonably likely to have a material adverse effect on the business, operations or financial condition of East Texas.

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 is also impacted by the timing of operating cash receipts and disbursements, borrowings of and payments on debt, capital expenditures, and increases or decreases in restricted investments and other long-term assets.

As of December 31, 2008, we had $48.0 million in cash and cash equivalents. Of this balance, as of December 31, 2008, $21.2 million was held by Collbran Valley Gas Gathering, or Collbran, our 70% owned joint venture which we consolidate in our financial results. Other than the cash held by Collbran, this cash balance was available for general corporate purposes.

We had working capital of $40.4 million as of December 31, 2008 and a working capital deficit of $1.1 million as of December 31, 2007. The changes in working capital are primarily attributable to the factors described above. We expect that our future working capital requirements will continue to be impacted by the factors identified above.

Cash Flow Operating, investing and financing activities was as follows:

	Year Ended December 31, 2008	2007	2006
		(Millions)	
Net cash provided by operating activities	$ 101.5	$ 65.4	$ 94.8
Net cash used in investing activities	$ (166.9)	$ (521.7)	$ (93.8)
Net cash provided by financing activities	$ 88.9	$ 434.6	$ 3.0

Our predecessor s sources of liquidity, prior to their acquisition by us, included cash generated from operations and funding from DCP Midstream, LLC. Our predecessor s cash receipts were deposited in DCP Midstream, LLC s bank accounts and all cash disbursements were made from these accounts. Cash transactions for our predecessor were handled by DCP Midstream, LLC and were reflected in partners equity as intercompany advances from DCP Midstream, LLC. We maintain our own bank accounts, which are managed by DCP Midstream, LLC.

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.

We and our predecessors received cash distributions from equity method investments of $59.9 million, $38.9 million and $25.9 million during the years ended December 31, 2008, 2007 and 2006, respectively. Distributions exceeded earnings by $25.6 million for the year ended December 31, 2008. Earnings exceeded distributions by $0.4 million and $3.3 million for the years ended December 31, 2007 and 2006, respectively.

Net Cash Used in Investing Activities Net cash used in investing activities during 2008 was primarily used for: (1) acquisition of MPP of $146.4 million; acquisition of the MEG subsidiaries of $10.9 million; (2) capital expenditures of $41.0 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities, including the pipeline integrity costs and system upgrades at Douglas and (3) investments in equity method investments of $13.8 million; and (4) acquisition of the MEG subsidiaries of $10.9 million; which were partially offset by (5) net proceeds from available-for-sale securities of $42.3 million; and (6) $2.9 million proceeds from the sale of assets.

Net cash used in investing activities during 2007 was primarily used for: (1) asset acquisitions of $191.3 million; (2) acquisition of equity method investments of $153.3 million; (3) acquisition of the MEG subsidiaries of $142.0 million; (4) capital expenditures of $21.3 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities and (5) investments in equity method investments of $16.3 million; which were partially offset by; (6) net proceeds from available-for-sale securities of $2.4 million.

During 2007, we acquired Discovery, East Texas and the Swap from DCP Midstream, LLC for an initial cash outlay of approximately $243.7 million. The historical value of the assets acquired of approximately $153.3 million is reflected in net cash used in investing activities. The remaining $90.4 million is reflected in net cash provided by financing 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 financing activities as the excess of the purchase price over the acquired assets.

We invested cash in equity method investments of $13.8 million, $16.3 million and $11.1 million during the years ended December 31, 2008, 2007 and 2006, respectively, of which $12.2 million, $6.9 million and $11.1 million, respectively, was to fund our share of capital expansion projects, $1.6 million in 2008 was to fund hurricane expenses and $9.4 million in 2007 was to fund working capital needs.

Net cash used in investing activities in 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 Financing Activities Net cash provided by financing activities during 2008 was comprised of; (1) proceeds from debt of $660.4 million; (2) the issuance of common units for $132.1 million, net of offering costs; (3) contributions from DCP Midstream, LLC of $4.1 million; and (4) net contributions from non-controlling interests of $2.4 million; partially offset by (5) repayment of debt of $633.9 million; and (6) distributions to our unitholders and general partner of $76.2 million.

During 2008, total outstanding indebtedness under our $824.6 million credit agreement, which includes borrowings under our revolving credit facility, our term loan facility and letters of credit issued under the credit agreement, was not less than $630.2 million and did not exceed $735.3 million. The weighted average indebtedness outstanding was $643.1 million, $690.0 million, $655.4 million and $666.6 million for the first, second, third and fourth quarters of 2008, respectively.

We had liquidity, which includes available commitments under the Credit Agreement and excludes cash on hand, of $364.7 million, $385.4 million, $390.4 million and $228.0 million at the end of the first, second, third and fourth quarters of 2008, respectively, which has been reduced by Lehman non-participation for all periods for comparative purposes.

During 2008, we had the following borrowings:

- $320.4 million borrowings for cash collateral postings with our commodity derivative contracts and for general working capital purposes. $293.9 million of these borrowings were repaid as of December 31, 2008;
- $150.0 million borrowing on our term loan facility, the proceeds of which were used to reduce borrowings on our revolving credit facility; and
- $190.0 million borrowing from our revolving credit facility, $146.4 million of which was used for the Michigan acquisition and the remainder was used for other capital expenditures.

Net cash provided by financing activities during 2007 was comprised of borrowings of $579.0 million, the issuance of common units for $228.5 million, net of offering costs, and contributions from non-controlling interests of $3.4 million, offset by repayment of debt of $217.0 million, the excess of purchase price over the acquired assets attributable to a payment related to our acquisition of Discovery, East Texas and the Swap of $90.4 million and of our wholesale propane logistics business of $9.9 million, distributions to our unitholders of $44.0 million, and net change in advances from DCP Midstream, LLC of $14.6 million.

During 2007, we had the following borrowings:

- $11.0 million under our revolving credit facility to fund the purchase of the Laser assets from Midstream;
- $89.0 million under our revolving credit facility to partially fund the Southern Oklahoma acquisition;
- $88.0 million under a bridge loan to partially fund the Southern Oklahoma acquisition, which was extinguished with borrowings under our revolving credit facility;
- $246.0 million from our revolving credit facility to finance the acquisition of our interests in East Texas and Discovery;
- $100.0 million from our term loan facility and $35.0 million from our revolving credit facility to finance the MEG acquisition and for general corporate purposes; and
- $10.0 million from our revolving credit facility for general corporate purposes, which was subsequently repaid.

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 unitholders, repayments of debt, changes in parent advances and the excess purchase price of our wholesale propane logistics business over its historical basis.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. 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. 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.

We incur capital expenditures for our consolidated entities and our equity method investments. We anticipate maintenance capital expenditures of $10.0 to $15.0 million, and expansion capital expenditures of $65.0 million, for the year ending December 31, 2009. Maintenance capital includes an estimated $5.0 million to complete the pipeline integrity and system upgrades to our Douglas system. DCP Midstream, LLC has agreed to reimburse us for our share of Discovery s capital expenditures for the Tahiti pipeline lateral. The board of directors may approve additional growth capital during the year, at their discretion.

Our capital expenditures, excluding acquisitions, totaled $41.0 million and $21.3 million, including maintenance capital expenditures of $11.3 million and $2.4 million, and expansion capital expenditures of $29.7 million and $18.9 million, during 2008 and 2007, respectively. Maintenance capital in 2008 included $6.8 million associated with the pipeline integrity and system upgrades to our Douglas system. In conjunction with the acquisition of our investments in East Texas and Discovery, we entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for 25%, and will reimburse us for 40%, of certain capital expenditures as defined in the agreement, from July 1, 2007 through completion of the capital projects, for a period not to exceed three years. 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, 2008, we had an increase in receivables of $0.3 million and during the year ended December 31, 2007, we had a decrease in receivables of $0.2 million related to collections of maintenance capital expenditures from DCP Midstream, LLC and producers. As a result, our total maintenance capital expenditures net of reimbursements were approximately $11.0 million and $2.6 million for the years ended December 31, 2008 and 2007, respectively.

During the third quarter of 2008, we announced that Collbran Valley Gas Gathering, LLC, or Collbran, plans to invest approximately $150.0 million over a multi-year period to construct approximately 20 miles of 24-inch diameter gathering pipeline, and compression and liquids handling facilities, to support its Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. We are the operator and 70% owner of Collbran. We ultimately expect to invest approximately $105.0 million in this project, which is in proportion to our ownership interest. The gathering system is designed to ultimately have throughput capacity of over 600 million cubic feet per day, or MMcf/d, and is supported by long-term acreage dedications. Our share of the Collbran investment was approximately $5.6 million in 2008 and we will invest approximately $57.0 million in 2009 to achieve throughput capacity of approximately 200 MMcf/d in the third quarter of 2009. Our share of the remaining investment in primarily compression equipment of approximately $42.4 million may be spent in 2010 and beyond as production volumes increase, providing total throughput capacity in excess of 600 MMcf/d.

During the third quarter of 2008, we announced plans, along with DCP Midstream, LLC, to invest approximately $56.0 million in East Texas to construct a gathering pipeline to support the East Texas system. Our interest in this pipeline is currently 25%. Our net investment is approximately $14.0 million. Of that total, we spent approximately $1.3 million in 2008 and expect to spend the remaining $12.7 million in 2009. The pipeline is scheduled to be operational during the second quarter of 2009.

During the third quarter of 2008, we announced plans to pursue development of a natural gas pipeline in the Haynesville shale in northern Louisiana. Development of a potential pipeline project is highly dependent upon drilling and development plans in the area, securing appropriate levels of shipper contractual commitments and securing financing. We spent approximately $2.3 million in 2008 on this project.

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, which could include other debt and common unit issuances, to fund our acquisition and expansion capital expenditures.

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. If these sources are not sufficient, we may reduce our capital spending.

Given our long-term strategy of profitable growth, our long-term objective is to obtain an investment grade credit rating, to increase our available sources to fund capital expenditures.

Cash Distributions to Unitholders Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders and general partner of $76.2 million and $44.0 million during 2008 and 2007, respectively. We intend to continue making quarterly distribution payments to our unitholders to the extent we have sufficient cash from operations after the establishment of reserves.

Description of the Credit Agreement On June 21, 2007, we entered into an Amended and Restated Credit Agreement, or the Credit Agreement, which amended our existing Credit Agreement. This new 5-year Credit Agreement consists of a $764.6 million revolving credit facility and a $60.0 million term loan facility, and matures on June 21, 2012. The amendment also improved pricing and certain other terms and conditions of the Credit Agreement. As of December 31, 2008, the outstanding balance on the revolving credit facility was $596.5 million and the outstanding balance on the term loan facility was $60.0 million.

Our obligations under the revolving credit facility are unsecured, and the term loan facility is secured at all times by high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheets, 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 would 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. The unused portion of the revolving credit facility may be used for letters of credit. At December 31, 2008 and 2007, there were outstanding letters of credit issued under the Credit Agreement of $0.3 million and $0.2 million, respectively.

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 either: (1) the higher of Wachovia Bank s prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our leverage level or credit rating. As of December 31, 2008, the weighted-average interest rate on our revolving credit facility was 2.08% per annum. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to either: (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank s prime rate or the Federal Funds rate plus 0.50%. As of December 31, 2008, the interest rate on our term loan facility was 1.54%.

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 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.5 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 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

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Bridge Loan

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provided for borrowings up to $100.0 million, and had terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100.0 million, which was due and payable no later than August 9, 2007.

We used borrowings on the Bridge Loan of $88.0 million to partially fund the Southern Oklahoma acquisition. The remaining $12.0 million available for borrowing on the Bridge Loan was not utilized. We used a portion of the net proceeds of the private placement to extinguish the $88.0 million outstanding on the Bridge Loan in June 2007.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of December 31, 2008, is as follows:

	Payments Due by Period				
	Total	2009	2010-2011	2012-2013	2014 and Thereafter
			(Millions)		
Long-term debt(a)	$ 733.4	$ 26.6	$ 42.4	$ 664.4	$
Operating lease obligations	44.7	12.4	16.9	12.8	2.6
Purchase obligations(b)	632.8	140.8	201.9	188.2	101.9
Other long-term liabilities(c)	8.5		0.4	0.1	8.0
Total	$ 1,419.4	$ 179.8	$ 261.6	$ 865.5	$ 112.5

(a) Includes interest payments on long-term debt that 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 include $3.3 million of purchase orders for capital expenditures and $629.5 million of various non-cancelable commitments to purchase physical quantities of commodities in future periods. For contracts where the price paid is based on an index, the amount is based on the forward market prices at December 31, 2008. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the consolidated balance sheet, which 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 of the underlying commodity. 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 $7.9 million of asset retirement obligations and $0.6 million of environmental reserves, recognized on the consolidated balance sheet.

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

Recent Accounting Pronouncements

Statement of Financial Accounting Standards, or SFAS, No. 162 The Hierarchy of Generally Accepted Accounting Principles, **or SFAS 162** In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We have assessed the impact of the adoption of SFAS 162, and believe that there will be no impact on our consolidated results of operations, cash flows or financial position.

***FASB Staff Position, or FSP, No. SFAS 142-3 Determination of the Useful Life of Intangible Assets,* or FSP 142-3** In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3 but do not expect a material impact on our consolidated results of operations, cash flows and financial position as a result of adoption.

***SFAS No. 161 Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133,* or SFAS 161** In March 2008, the FASB issued SFAS 161, which requires disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 161 on our disclosures, and will make the required disclosures in our March 31, 2009 consolidated financial statements.

***SFAS No. 160 Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51,* or SFAS 160** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 was effective for us on January 1, 2009, and did not have a significant impact on our consolidated results of operations, cash flows or financial position. As a result of adoption effective January 1, 2009, we will reclassify our non- controlling interests in the consolidated balance sheets to partners equity.

***SFAS No. 141(R) Business Combinations (revised 2007),* or SFAS 141(R)** In December 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

***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. The provisions of SFAS 159 became effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in 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 was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;
- establishes a framework for measuring fair value;
- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;
- nullifies the guidance in Emerging Issues Task Force, or EITF, 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities*, which required the deferral of profit at inception of a transaction involving a derivative financial instrument in the absence of observable data supporting the valuation technique; and
- significantly expands the disclosure requirements around instruments measured at fair value.

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we recorded a transition adjustment of approximately $5.8 million as an increase to earnings and approximately $1.3 million as an increase to AOCI during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we are in the process of assessing the impact SFAS 157 will have on our non-financial assets and liabilities, but do not expect a material impact on our consolidated results of operations, cash flows or financial positions upon adoption.

***FSP No. 157-3 Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active*, or FSP 157-3** In October 2008, the FASB issued FSP 157-3, which provides guidance in situations where a) observable inputs do not exist, b) observable inputs exist but only in an inactive market and c) how market quotes should be considered when assessing the relevance of observable and unobservable inputs to determine fair value. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. We believe that the financial assets that are reflected in our financial statements are transacted within active markets, and therefore no adjustment to our fair value methodology was required and there is no effect on our consolidated results of operations, cash flows or financial positions as a result of the adoption of this FSP.

***FSP of Financial Interpretation, or FIN, 39-1, Amendment of FASB Interpretation No. 39*, or FSP FIN 39-1** In April 2008, the FASB issued FSP FIN 39-1, which permits, but does not require, a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 became effective for us beginning on January 1, 2008; however, we have elected to continue our policy of reflecting our derivative asset and liability positions, as well as any cash collateral, on a gross basis in our consolidated balance sheets.

***EITF 08-06 Equity Method Investment Accounting Considerations*, or EITF 08-06** In November 2008, the EITF issued ETIF 08-06. Although the issuance of FAS 141(R) and FAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how an impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee s issuance of shares should be accounted for and d) how to account for a change in an investment from the equity method to the cost method. This issue is effective for us on January 1, 2009, and although we do not expect any changes to the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

***EITF 07-04 Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships* or EITF 07-04** In March 2008, the EITF issued ETIF 07-04. This issue seeks to improve the comparability of earnings per unit, or EPU, calculations for master limited partnerships with incentive distribution rights in accordance with FASB Statement No. 128 and its related interpretations. This issue is effective for us on January 1, 2009 and will be incorporated into our EPU calculations beginning with the quarter ending March 31, 2009. We are in the process of assessing the impact of EITF 07-04 on our EPU calculations, and will make any required changes to our calculation methodology for the quarter ending March 31, 2009.

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 mitigate 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

We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and 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 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 Note 2, Accounting for Risk Management Activities and Financial Instruments, of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data 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, as 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.

We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $575.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. 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. At December 31, 2008, the effective weighted-average interest rate on our $596.5 million of outstanding revolver debt was 4.48%, taking into account the $575.0 million of indebtedness with designated interest rate swaps.

Based on the annualized unhedged borrowings under our credit facility of $81.5 million as of December 31, 2008, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.4 million annualized increase or decrease in interest expense.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, and sales activities. For gathering services, we receive fees or commodities from producers to bring the natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, depending on the types of contracts. 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.

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

We enter into derivative financial instruments to mitigate the risk of weakening natural gas, NGL and condensate prices associated with our percent-of-proceeds arrangements and gathering operations. Historically, there has been a strong correlation between NGL prices and crude oil prices and lack of liquidity in the NGL financial market; therefore we have historically used crude oil swaps to mitigate NGL price risk. As a result of these transactions, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk through 2013.

The derivative financial instruments we have entered into are typically referred to as swap contracts. These swap contracts entitle us to receive payment at settlement 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 at settlement to the counterparty to the extent that the reference price is higher than the swap price stated in the contract.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow protection activities. We are using the mark-to-market method of accounting for all commodity derivative instruments, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on derivative activity.

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

Period	Commodity	Notional Volume	Reference Price	Swap Price Range
January 2009 December 2009	Natural Gas	2,000 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2010 December 2010	Natural Gas	1,900 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2009 December 2013	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price(b)	$8.22/MMBtu
January 2009 December 2013	Natural Gas Basis	1,500 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line(c)	NYMEX less $0.68/MMBtu
January 2009 December 2009	Crude Oil	2,450 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$63.05 - $86.95/Bbl
January 2010 December 2010	Crude Oil	2,415 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$63.05 - $87.25/Bbl
January 2011 December 2011	Crude Oil	2,350 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$66.72 - $87.25/Bbl
January 2012 December 2012	Crude Oil	2,325 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$66.72 - $90.00/Bbl
January 2013 December 2013	Crude Oil	1,250 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$67.60 - $71.20/Bbl
March 2009 December 2010(f)	Natural Gas	1,634 MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline(e)	$3.94/MMBtu
April 2010 December 2011(f)	Crude Oil	250 Bbls/d	Asian-pricing of NYMBEX crude oil futures(d)	$56.75 - $59.30/Bbl

(a) The Inside FERC index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.

(b) NYMEX final settlement price for natural gas futures contracts (NG).

(c) The Inside FERC monthly published index price for Panhandle Eastern Pipe Line (Texas, Oklahoma mainline) less the NYMEX final settlement price for natural gas futures contracts.

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

(e) The Inside FERC index price for natural gas delivered into the Colorado Interstate Gas (CIG) pipeline.

(f) These trades were entered into subsequent to December 31, 2008.

At December 31, 2008, the aggregate fair value of the fixed price natural gas and crude oil swaps described above was a net gain of $6.5 million and $13.5 million respectively.

We utilize crude oil derivatives to mitigate a significant portion of our commodity price exposure for propane and heavier NGLs. Due to current movements in the relationship of NGL prices to crude oil prices outside of recent historical ranges, we have provided an additional sensitivity factor to capture movements up or down in this relationship. We have combined the NGL and crude oil sensitivities into one factor, and added our sensitivity to changes in the relationship between the pricing of NGLs and crude oil. For fixed price natural gas and crude oil, the sensitivities are associated with our unhedged volumes. For our NGL to crude oil price relationship, the sensitivity is associated with both hedged and unhedged equity volumes. Given our current contract mix and the commodity derivative contracts we have in place, we have updated our annualized sensitivities for 2009 as shown in the table below, which excludes the impact from mark-to-market on our commodity derivatives.

Commodity Sensitivities Excluding Non-Cash Mark-To-Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 0.3
Crude oil prices(a)	$ 5.00	Barrel	$ 1.7
NGL to crude oil price relationship(b)	5 percentage point change	Barrel	$ 4.6

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(a) Assuming 60% NGL to crude oil price relationship.

(b) Assuming 60% NGL to crude oil price relationship and $60.00/Bbl crude oil price. Generally, this sensitivity changes by $1.5 million for each $20.00/Bbl change in the price of crude oil. As crude oil prices increase from $60.00/Bbl, we become slightly more sensitive to the change in the relationship of NGL prices to crude oil prices. As crude oil prices decrease from $60.00/Bbl, we become less sensitive to the change in the relationship of NGL prices to crude oil prices.

In addition to the linear relationships in our commodity sensitivities above, additional factors cause us to be less sensitive to commodity price declines. A portion of our net income is derived from fee-based contracts and a certain percentage of liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as NGL prices decline.

The above sensitivities exclude the impact from arrangements where producers on a monthly basis may elect to not process their natural gas in which case we retain a portion of the customers natural gas in lieu of NGLs as a fee. The above sensitivities also exclude certain related processing arrangements where we control the processing or by-pass of the production based upon individual economic processing conditions. Under each of these types of arrangements, our processing of the natural gas would yield favorable processing margins. Less than 10% of our gas throughput is associated with these arrangements.

We estimate the following non-cash sensitivities in 2009 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income) (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 4.9
Crude oil prices	$ 5.00	Barrel	$ 18.8

While the above commodity price sensitivities are indicative of the impact that changes in commodity prices may have on our annualized net income, changes during certain periods of extreme price volatility and market conditions or changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary significantly from these estimates.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally correlated to the price of crude oil, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close correlation. Changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing operations through 2013.

Based on historical trends, however, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather, and the domestic production and drilling activity level of exploration and production companies. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity in the future. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed, but would likely increase commodity prices.

Other 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 condensate. 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.

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.

We manage our commodity derivative activities in accordance with our Risk Management Policy which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Valuation Valuation of a contract s fair value is validated by an internal group independent of the marketing 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.

The fair value of our interest rate swaps and commodity non-trading derivatives 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 Contracts as of December 31, 2008
Maturity in 2014 and

Sources of Fair Value	Total	Maturity in 2009	Maturity in 2010-2011 (Millions)	Maturity in 2012-2013	Thereafter
Prices supported by quoted market prices and other external sources	$ (21.7)	$ (2.6)	$ (15.1)	$ (4.0)	$
Prices based on models or other valuation techniques	2.0	0.3	1.7		
Total	$ (19.7)	$ (2.3)	$ (13.4)	$ (4.0)	$

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The prices supported by quoted market prices and other external sources category includes our interest rate swaps, our New York Mercantile Exchange, or NYMEX, swap positions in natural gas, NGLs and our Asian-pricing NYMEX crude oil swaps, for which our fair value is based upon unadjusted quoted market prices for identical assets or liabilities in active markets. In addition, this category includes our forward positions in natural gas basis swaps for which our forward price curves are obtained from SunGard Kiodex and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes strip transactions whose pricing inputs are directly or indirectly observable 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 inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

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

INDEX TO FINANCIAL STATEMENTS

DCP MIDSTREAM PARTNERS, LP CONSOLIDATED FINANCIAL STATEMENTS:

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, 2008 and 2007, and the related consolidated statements of operations, comprehensive income (loss), changes in partners equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the Index at 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 did not audit the financial statements of Discovery Producer Services, LLC (Discovery), an investment of the Company which is accounted for by the use of the equity method. The Company s equity in Discovery s net assets of $145,054,000 and $161,519,000 at December 31, 2008 and 2007, respectively, and in Discovery s net income of $13,760,000, $19,229,000, and $12,033,000 for the years ended December 31, 2008, 2007 and 2006, respectively, are included in the accompanying consolidated financial statements. Discovery s financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to amounts included for Discovery, is based solely on the report of the other auditors.

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 and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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 consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

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 (Midstream) 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 Midstream as a whole.

Also as described in Note 1 to the consolidated financial statements through July 1, 2007, the portion of the accompanying consolidated financial statements attributable to DCP East Texas Holdings, LLC (East Texas) , Discovery and a nontrading derivative instrument (the Swap) have been prepared from the separate records maintained by Midstream and may not necessarily be indicative of the conditions that would have existed or the results of operations if East Texas, Discovery and the Swap had been operated as unaffiliated entities. Portions of certain expenses represent allocations made from, and are applicable to Midstream as a whole.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2008, 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 4, 2009 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP
Denver, Colorado
March 4, 2009

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 48.0	$ 24.5
Short-term investments		1.3
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.6 million and $1.2 million, respectively	43.6	81.7
Affiliates	36.8	52.1
Inventories	20.9	37.3
Unrealized gains on derivative instruments	15.4	3.1
Other	0.5	18.5
Total current assets	165.2	218.5
Restricted investments	60.2	100.5
Property, plant and equipment, net	629.3	500.7
Goodwill	88.8	80.2
Intangible assets, net	47.7	29.7
Equity method investments	175.4	187.2
Unrealized gains on derivative instruments	8.6	2.7
Other long-term assets	4.8	1.2
Total assets	$ 1,180.0	$ 1,120.7
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 44.8	$ 110.2
Affiliates	33.6	55.6
Unrealized losses on derivative instruments	17.7	30.9
Accrued interest payable	1.3	1.6
Other	27.4	21.3
Total current liabilities	124.8	219.6
Long-term debt	656.5	630.0
Unrealized losses on derivative instruments	26.0	70.0
Other long-term liabilities	8.9	5.8

Total liabilities	816.2	925.4
Non-controlling interests	34.7	26.9
Commitments and contingent liabilities		
Partners equity:		
Common unitholders (24,661,754 and 16,840,326 units issued and outstanding, respectively)	429.0	308.8
Subordinated unitholders (3,571,429 and 7,142,857 convertible units issued and outstanding, respectively)	(54.6)	(120.1)
General partner interest	(4.8)	(5.4)
Accumulated other comprehensive loss	(40.5)	(14.9)
Total partners equity	329.1	168.4
Total liabilities and partners equity	$ 1,180.0	$ 1,120.7

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2008	2007	2006
	(Millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 678.5	$ 628.1	$ 535.1
Sales of natural gas, propane, NGLs and condensate to affiliates	477.8	297.7	232.8
Transportation, processing and other	31.2	18.5	15.0
Transportation, processing and other to affiliates	26.0	16.6	12.8
Gains (losses) from commodity derivative activity, net	75.4	(83.1)	
(Losses) gains from commodity derivative activity, net affiliates	(3.1)	(4.5)	0.1
Total operating revenues	1,285.8	873.3	795.8
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	798.3	647.4	581.2
Purchases of natural gas, propane and NGLs from affiliates	262.9	179.3	119.2
Operating and maintenance expense	43.0	32.1	23.7
Depreciation and amortization expense	36.5	24.4	12.8
General and administrative expense	12.4	14.1	12.9
General and administrative expense affiliates	11.6	10.0	8.1
Other	(1.5)		
Total operating costs and expenses	1,163.2	907.3	757.9
Operating income (loss)	122.6	(34.0)	37.9
Interest income	5.6	5.3	6.3
Interest expense	(32.8)	(25.8)	(11.5)
Earnings from equity method investments	34.3	39.3	29.2
Non-controlling interest in income	(3.9)	(0.5)	
Income (loss) before income taxes	125.8	(15.7)	61.9
Income tax expense	(0.1)	(0.1)	
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Less:			
Net income attributable to predecessor operations		(3.6)	(26.6)
General partner interest in net income	(11.9)	(2.2)	(0.7)
Net income (loss) allocable to limited partners	$ 113.8	$ (21.6)	$ 34.6

Net income (loss) per limited partner unit basic and diluted	$	3.25	$	(1.05)	$	1.90
Weighted-average limited partner units outstanding basic and diluted		27.4		20.5		17.5

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2008	2007	2006
		(Millions)	
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Other comprehensive income (loss):			
Reclassification of cash flow hedges into earnings	7.5	(3.1)	(2.7)
Net unrealized (losses) gains on cash flow hedges	(33.1)	(19.1)	9.6
Total other comprehensive (loss) income	(25.6)	(22.2)	6.9
Total comprehensive income (loss)	$ 100.1	$ (38.0)	$ 68.8

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS EQUITY

	Predecessor Equity	Common Unitholders	Class C Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Total Partners Equity
				(Millions)			
Balance, January 1, 2006	$ 219.8	$ 215.8	$	$ (109.7)	$ (5.6)	$ 0.4	$ 320.7
Net change in parent advances	(25.4)						(25.4)
Acquisition of wholesale propane logistics business	(56.7)						(56.7)
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 income attributable to predecessor operations	26.6						26.6
Net income		20.4	0.1	14.1	0.7		35.3
Other comprehensive income						6.9	6.9
Balance, December 31, 2006	164.3	223.4	(20.7)	(101.6)	(5.0)	7.3	267.7
Net change in parent advances	(14.6)						(14.6)
Acquisition of East Texas, Discovery and the Swap	(153.3)	27.0			0.6		(125.7)
Excess purchase price over acquired assets		(118.0)					(118.0)
Acquisition of Momentum Energy Group, Inc.		12.0					12.0
Purchase of units		(0.3)					(0.3)
Issuance of units		0.3					0.3
Issuance of 5,386,732 common units		228.5					228.5
Conversion of Class C units to common units		(20.7)	20.7				
Contributions by unitholders		0.2		0.6			0.8
Distributions to unitholders		(27.0)	(0.2)	(14.1)	(3.2)		(44.5)
Equity-based compensation		0.2					0.2

Net income attributable to predecessor operations	3.6						3.6
Net income (loss)		(16.8)	0.2	(5.0)	2.2		(19.4)
Other comprehensive loss						(22.2)	(22.2)
Balance, December 31, 2007		308.8		(120.1)	(5.4)	(14.9)	168.4
Issuance of 4,250,000 common units		132.1					132.1
Conversion of subordinated units to common units		(66.4)		66.4			
Contributions by unitholders		4.0					4.0
Distributions to unitholders and general partner		(53.9)		(10.5)	(11.3)		(75.7)
Equity-based compensation		0.2					0.2
Net income		104.2		9.6	11.9		125.7
Other comprehensive loss						(25.6)	(25.6)
Balance, December 31, 2008	$	$ 429.0	$	$ (54.6)	$ (4.8)	$ (40.5)	$ 329.1

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
		(Millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization expense	36.5	24.4	12.8
Earnings from equity method investments, net of distributions	25.6	(0.4)	(3.3)
Non-controlling interest in income	3.9	0.5	
Other, net	(0.4)	(0.2)	(2.4)
Change in operating assets and liabilities which provided (used) cash, net of effects of acquisitions:			
Accounts receivable	55.4	(42.2)	43.1
Inventories	16.4	(7.2)	11.6
Net unrealized (gains) losses on derivative instruments	(101.0)	81.1	(0.1)
Accounts payable	(79.7)	38.9	(31.5)
Accrued interest	(0.3)	0.5	0.3
Other current assets and liabilities	19.8	(16.4)	2.0
Other long-term assets and liabilities	(0.4)	2.2	0.4
Net cash provided by operating activities	101.5	65.4	94.8
INVESTING ACTIVITIES:			
Capital expenditures	(41.0)	(21.3)	(27.2)
Acquisition of Michigan Pipeline & Processing, LLC, net of cash acquired	(146.4)		
Acquisition of subsidiaries of Momentum Energy Group, Inc., net of cash acquired	(10.9)	(142.0)	
Acquisition of assets		(191.3)	
Acquisition of equity method investments		(153.3)	
Investments in equity method investments	(13.8)	(16.3)	(11.1)
Payment of earnest deposit		(9.0)	
Refund of earnest deposit		9.0	
Acquisition of wholesale propane logistics business			(56.7)
Proceeds from sales of assets	2.9	0.1	0.3
Purchases of available-for-sale securities	(608.2)	(6,921.6)	(7,372.4)
Proceeds from sales of available-for-sale securities	650.5	6,924.0	7,373.3
Net cash used in investing activities	(166.9)	(521.7)	(93.8)

FINANCING ACTIVITIES:			
Proceeds from debt	660.4	579.0	78.0
Payments of debt	(633.9)	(217.0)	(20.1)
Payment of deferred financing costs		(0.6)	(0.2)
Purchase of units		(0.3)	
Proceeds from issuance of common units, net of offering costs	132.1	228.5	
Proceeds from issuance of equivalent units to general partner			0.1
Excess purchase price over acquired assets		(100.3)	(10.7)
Net change in advances from DCP Midstream, LLC		(14.6)	(25.4)
Distributions to unitholders and general partner	(76.2)	(44.0)	(22.1)
Distributions to non-controlling interests	(3.3)		
Contributions from non-controlling interests	5.7	3.4	
Contributions from DCP Midstream, LLC	4.1	0.5	3.4
Net cash provided by financing activities	88.9	434.6	3.0
Net change in cash and cash equivalents	23.5	(21.7)	4.0
Cash and cash equivalents, beginning of period	24.5	46.2	42.2
Cash and cash equivalents, end of period	$ 48.0	$ 24.5	$ 46.2

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years Ended December 31, 2008, 2007 and 2006

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, producing, transporting, storing and selling propane and transporting and selling NGLs and condensate.

We are a Delaware master limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our Northern Louisiana system; our Southern Oklahoma system (acquired in May 2007); our limited liability company interests in DCP East Texas Holdings, LLC, or East Texas, and Discovery Producer Services LLC, or Discovery (acquired in July 2007); our Wyoming system and a 70% interest in our Colorado system (each acquired in August 2007); our Michigan systems (acquired in October 2008); our wholesale propane logistics business (acquired in November 2006); and our NGL transportation pipelines.

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 and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. 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. DCP Midstream, LLC owns approximately 30% of our partnership.

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, 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, and our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007. These were transactions among 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; accordingly, our financial information includes the historical results of our wholesale propane logistics business, Discovery and East Texas for all periods presented. 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. In addition, the results of operations of our Southern Oklahoma, Wyoming and Colorado systems, and our Michigan systems, have been included in the consolidated financial statements since their respective acquisition dates.

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, the assets, liabilities and operations of our wholesale propane logistics business, our equity interests in East Texas and Discovery, and the Swap, prior to our acquisition from DCP Midstream, LLC, 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.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 consolidated 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.

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 We may invest available cash balances in various financial instruments, such as commercial paper, money market instruments and 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 are used as collateral to secure the term loan portion of our credit facility and to finance gathering and compression asset acquisitions. We have classified all short-term and restricted investments as available-for-sale 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 (loss), or AOCI. 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.

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.

Property, Plant and Equipment Property, plant and equipment are recorded at historical cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

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 is determined using a risk free interest rate, and 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. 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, the excess of the carrying value over the fair value is recognized as an impairment loss.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Intangible assets consist primarily of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit.

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 sum of the undiscounted 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 and discounted cash flow models. 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.

Equity Method Investments We use the equity method to 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.

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 a 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 and discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

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

Non-Controlling Interest Non-controlling interest represents (1) the non-controlling interest holders ownership interests in the net assets of Collbran Valley Gas Gathering, a joint venture acquired in conjunction with the MEG acquisition in August 2007; and (2) the non controlling interest holders portion of the net

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

assets of Jackson Pipeline Company, a partnership we acquired with the Michigan acquisition in October 2008. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party interest in our consolidated balance sheet amounts shown as non-controlling interest. Distributions to and contributions from non-controlling interests represent cash payments and cash contributions, respectively, from such third-party investors.

Accounting for Risk Management Activities and Financial Instruments Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow protection activities. We are using the mark-to-market method of accounting for all commodity derivative instruments beginning in July 2007. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the underlying transactions impact earnings.

Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on derivative instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on derivative 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. Prior to July 1, 2007, we designated each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives were 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 derivative activity. For the periods presented, we did not have any trading derivative activity, however, we did 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(b)	Net basis in gains and losses from derivative activity
Cash Flow Hedge(a)	Hedge method(c)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge(a)	Hedge method(c)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method(d)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale

(a)

Effective July 1, 2007, all commodity cash flow hedges are classified as non-trading derivative activity. Our interest rate swaps continue to be accounted for as cash flow hedges. As of December 31, 2007 we no longer use fair value hedges.

(b) 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 and losses from derivative activity during the current period.

(c) 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 derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

(d) 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 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 derivative 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 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 derivative 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 gathering, processing, compressing, transporting, and fractionating natural gas and NGLs, and from trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees from the producers.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.

Percent-of-proceeds arrangements Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from 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. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percent-of-proceeds arrangements correlate directly with the price of natural gas and/or 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.

Collectibility is probable Collectibility 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, credit metrics, liquidity and credit rating) and their ability to pay. If collectibility is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is not recognized until the cash is collected.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 commodity derivative activity net in the consolidated statements of operations as gains and losses from commodity derivative activity. These activities include mark-to-market gains and losses on energy trading contracts and the settlement of financial or physical energy trading contracts.

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. Included in the consolidated balance sheets as accounts receivable trade and accounts receivable affiliates were imbalances of $3.8 million and $1.6 million at December 31, 2008 and 2007, respectively. Included in the consolidated balance sheets as accounts payable trade were imbalances of $1.4 million and $1.1 million at December 31, 2008 and 2007, respectively.

Significant Customer There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2008, 2007 and 2006. In addition, there were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2008, 2007 and 2006 in any of our business segments. We also had significant transactions with affiliates, and with suppliers of natural gas and propane.

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, 2008 and 2007, included in the consolidated balance sheets as other current liabilities amounted to $1.3 million and $0.7 million, respectively, and as other long-term liabilities amounted to $0.6 million and $1.0 million, respectively.

Equity-Based Compensation Equity classified stock-based compensation cost is measured at fair value, based on the closing common unit price at grant date, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date at fair value, based on the closing common unit price, and is recognized as expense 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 for acquiring, or in conjunction with selling, goods and services, are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Income Taxes We are structured as a master limited partnership which is a pass-through entity for federal income tax purposes. Our income tax expense includes certain jurisdictions, including state, local, franchise and margin taxes of the master limited partnership and subsidiaries. We follow the asset and liability method of accounting for income taxes. Under this method, 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. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is included in the federal returns of each partner.

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

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net Income or Loss per Limited Partner Unit Basic and diluted net income or loss per limited partner unit is calculated by dividing limited partners interest in net income or loss, less pro forma general partner incentive distributions, by the weighted-average number of outstanding limited partner units during the period.

3. Recent Accounting Pronouncements

***Statement of Financial Accounting Standards, or SFAS, No. 162 The Hierarchy of Generally Accepted Accounting Principles,* or SFAS 162** In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the Securities and Exchange Commission, or SEC, approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We have assessed the impact of the adoption of SFAS 162, and believe that there will be no impact on our consolidated results of operations, cash flows or financial position.

***FASB Staff Position, or FSP, No. SFAS 142-3 Determination of the Useful Life of Intangible Assets,* or FSP 142-3** In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3, but do not expect a material impact on our consolidated results of operations, cash flows and financial position as a result of adoption.

***SFAS No. 161 Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*, or SFAS 161** In March 2008, the FASB issued SFAS 161, which requires disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 161 on our disclosures, and will make the required disclosures in our March 31, 2009 consolidated financial statements.

***SFAS No. 160 Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51*, or SFAS 160** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 was effective for us on January 1, 2009, and did not have a significant impact on our consolidated results of operations, cash flows or financial position. As a result of adoption effective January 1, 2009, we will reclassify non-controlling interests in the consolidated balance sheets to partners equity.

***SFAS No. 141(R) Business Combinations (revised 2007)*, or SFAS 141(R)** In December 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***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. The provisions of SFAS 159 became effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in 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 was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;

- establishes a framework for measuring fair value;

- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;

- nullifies the guidance in Emerging Issues Task Force, or EITF, 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities*, which required the deferral of profit at inception of a transaction involving a derivative financial instrument in the absence of observable data supporting the valuation technique; and

- significantly expands the disclosure requirements around instruments measured at fair value.

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we recorded a transition adjustment of approximately $5.8 million as an increase to earnings and approximately $1.3 million as an increase to AOCI during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we are in the process of assessing the impact SFAS 157 will have on our non-financial assets and liabilities, but do not expect a material impact on our consolidated results of operations, cash flows or financial position upon adoption.

***FSP No. 157-3 Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active,* or FSP 157-3** In October 2008, the FASB issued FSP 157-3, which provides guidance in situations where a) observable inputs do not exist, b) observable inputs exist but only in an inactive market and c) how market quotes should be considered when assessing the relevance of observable and unobservable inputs to determine fair value. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. We believe that the financial assets that are reflected in our financial statements are transacted within active markets, and therefore, there is no effect on our consolidated results of operations, cash flows or financial positions as a result of the adoption of this FSP.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***FSP of Financial Interpretation, or FIN, 39-1, Amendment of FASB Interpretation No. 39,* or FSP FIN 39-1** In April 2007, the FASB issued FSP FIN 39-1, which permits, but does not require, a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 became effective for us beginning on January 1, 2008; however, we have elected to continue our policy of reflecting our derivative asset and liability positions, as well as any cash collateral, on a gross basis in our consolidated balance sheets.

***EITF 08-06 Equity Method Investment Accounting Considerations*, or EITF 08-06** In November 2008, the EITF issued ETIF 08-06. Although the issuance of FAS 141(R) and FAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how an impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee s issuance of shares should be accounted for and d) how to account for a change in an investment from the equity method to the cost method. This issue is effective for us on January 1, 2009, and although we do not expect any changes to the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

***EITF 07-04 Application of the Two Class Method under FASB Statement No. 128 to Master Limited Partnerships* or EITF 07-04** In March 2008, the EITF issued ETIF 07-04. This issue seeks to improve the comparability of earnings per unit, or EPU, calculations for master limited partnerships with incentive distribution rights in accordance with FASB Statement No. 128 and its related interpretations. This issue is effective for us on January 1, 2009 and will be incorporated into our EPU calculations beginning with the quarter ending March 31, 2009. We are in the process of assessing the impact of EITF 07-04 on our EPU calculations, and will make any required changes to our calculation methodology for the quarter ending March 31, 2009.

4. Acquisitions

Gathering and Compression Assets

On October 1, 2008, we acquired Michigan Pipeline & Processing, LLC, or MPP, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. The results of MPP s operations have been included in the consolidated financial statements since that date. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.4 million, subject to additional customary purchase price adjustments. We may pay up to an additional $15.0 million to the sellers depending on the earnings of the assets after a three-year period. We financed the acquisition through utilization of our credit facility. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay up to $1.5 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments would reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. Certain of these performance criteria were satisfied, and as a result, the amount was reduced to approximately $0.8 million per year as of December 31, 2008. We initially held a $25.0 million letter of credit to secure the seller s performance under this agreement and to secure the seller s indemnification obligation under the acquisition agreement; however as a result of the satisfaction of certain performance conditions, this amount was reduced to approximately $22.5 million as of December 31, 2008. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Under the purchase method of accounting, the assets and liabilities of MPP were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $6.7 million. The goodwill amount recognized relates primarily to projected growth from new customers. The values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained, which when finalized may result in material adjustments. The purchase price allocation is as follows:

		(Millions)
Cash	$	1.7
Accounts receivable		2.1
Other assets		0.1
Other long term assets		3.8
Property, plant and equipment		116.1
Goodwill		6.7
Intangible assets		20.0
Other liabilities		(0.5)
Non-controlling interest in joint venture		(1.6)
Total purchase price allocation	$	148.4

In August 2007, we acquired certain subsidiaries of Momentum Energy Group, Inc., or MEG, from DCP Midstream, LLC for approximately $165.8 million. As a result of the acquisition, we expanded our operations into the Piceance and Powder River producing basins, thus diversifying our business into new operating areas. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments totaling $10.9 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of borrowings under our credit agreement, along with the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate. The proceeds from this private placement were used to purchase high-grade securities to fully secure our term loan borrowings. These units were registered with the SEC in January 2008.

The transfer of the MEG subsidiaries between DCP Midstream, LLC and us represents a transfer between entities under common control. Transfers between entities under common control are accounted for at DCP Midstream, LLC s carrying value, similar to the pooling method. DCP Midstream, LLC recorded its acquisition of the MEG subsidiaries under the purchase method of accounting, whereby the assets and liabilities were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $52.8 million, including purchase price adjustments of $1.9 million during the first quarter of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2008. The goodwill amount recognized relates primarily to projected growth in the Piceance basin due to significant natural gas reserves and high levels of drilling activity. The purchase price allocation is as follows:

	(Millions)
Cash consideration	$ 153.8
Payable to DCP Midstream, LLC	10.9
Common limited partner units	12.0
Aggregate consideration	$ 176.7
The purchase price allocation is as follows:	
Cash	$ 11.8
Accounts receivable	14.1
Other assets	1.5
Property, plant and equipment	127.8
Goodwill	52.8
Intangible assets	15.5
Accounts payable	(11.1)
Other liabilities	(12.9)
Non-controlling interest in joint venture	(22.8)
Total purchase price allocation	$ 176.7

On July 1, 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC, for aggregate consideration of approximately $271.3 million, consisting of approximately $243.7 million in cash, including net working capital of $1.3 million and other adjustments, the issuance of 620,404 common units to DCP Midstream, LLC valued at $27.0 million and the issuance of 12,661 general partner equivalent units valued at $0.6 million. We financed the cash portion of this transaction with borrowings of $245.9 million under our credit facility. The $118.0 million excess purchase price over the historical basis of the net acquired assets was recorded as a reduction to partners equity, and the $27.6 million of common and general partner equivalent units issued as partial consideration for this transaction was recorded as an increase to partners equity.

In May 2007, we acquired certain gathering and compression assets located in southern Oklahoma, or the Southern Oklahoma system, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation for approximately $181.1 million.

In April 2007, we acquired certain gathering and compression assets located in northern Louisiana from Laser Gathering Company, LP for approximately $10.2 million.

The results of operations for MPP, MEG, and the Southern Oklahoma and northern Louisiana acquired assets, have been included prospectively, from the dates of acquisition, as part of the Natural Gas Services segment.

Wholesale Propane Logistics Business

On November 1, 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC, in a transaction among entities under common control, for aggregate consideration of approximately $82.9 million, which consisted of $77.3 million in 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 incurred through October 31, 2006, which were associated with the construction of a new pipeline terminal. The $26.3 million excess purchase price over the historical basis of

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the net acquired assets was recorded as a reduction to partners equity, and the $5.6 million of common and general partner equivalent units issued as partial consideration for this transaction was recorded as an increase to partners equity.

Combined Financial Information

The following table presents pro forma information for the consolidated statements of operations for the years ended 2008 and 2007, as if the acquisition of MPP had occurred at the beginning of each year presented. There is no impact shown for the MEG acquisition because there were no predecessor operations of MEG at DCP Midstream, LLC.

	2008			2007		
	DCP Midstream Partners, LP	Acquisition of MPP	DCP Midstream Partners, LP Pro Forma	DCP Midstream Partners, LP	Acquisition of MPP	DCP Midstream Partners, LP Pro Forma
	(Millions, except per unit amounts)					
Total operating revenues	$ 1,285.8	$ 14.8	$ 1,300.6	$ 873.3	$ 20.9	$ 894.2
Net income (loss)	$ 125.7	$ 2.2	$ 127.9	$ (15.8)	$ 1.2	$ (14.6)
Less:						
Net income attributable to predecessor operations				(3.6)		(3.6)
General partner interest in net income	(11.9)		(11.9)	(2.2)	(0.1)	(2.3)
Net income (loss) allocable to limited partners	$ 113.8	$ 2.2	$ 116.0	$ (21.6)	$ 1.1	$ (20.5)
Net income (loss) per limited partner unit basic and diluted	$ 3.25	$ 0.04	$ 3.29	$ (1.05)	$ 0.05	$ (1.00)

The pro forma information is not intended to reflect actual results that would have occurred if the companies had been combined during the periods presented, nor is it intended to be indicative of the results of operations that may be achieved by us in the future.

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 investments, 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, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee 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, taxes and engineering. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, totaling $43.0 million at December 31, 2008, to certain counterparties to our commodity derivative instruments.

All of the fees under the Omnibus Agreement are subject to adjustment annually for changes in the Consumer Price Index.

The Omnibus Agreement also addresses the following matters:

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 in December 2005, 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).

Following is a summary of the fees we incurred under the Omnibus Agreement and the effective date for these fees, as well as other fees paid to DCP Midstream, LLC:

		Year Ended December 31,		
Terms	**Effective Date**	**2008**	**2007**	**2006**
			(Millions)	
Annual fee	2006	$ 5.1	$ 5.0	$ 4.8
Wholesale propane logistics business	November 2006	2.0	2.0	0.3

Southern Oklahoma	May 2007	0.2	0.1	
Discovery	July 2007	0.2	0.1	
Additional services	August 2007	0.6	0.2	
Momentum Energy Group, Inc.	August 2007	1.6	0.5	
Michigan Pipeline & Processing, LLC	October 2008	0.1		
Total Omnibus Agreement		9.8	7.9	5.1
Other fees		1.8	2.1	3.0
Total		$ 11.6	$ 10.0	$ 8.1

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Black Lake pipeline has experienced increased operating costs due to pipeline integrity testing that commenced in 2005 and was completed during the second quarter of 2008. Testing revealed irregularities, the more severe of which were repaired in October 2008 and the less severe of which are scheduled for repair in 2009. DCP Midstream, LLC agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing. We anticipate repairs of approximately $0.8 million on the pipeline, which will be funded directly from Black Lake. We will not make contributions to Black Lake to cover these expenses.

In connection with our acquisition of our wholesale propane logistics business, DCP Midstream, LLC agreed to indemnify us until October 31, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing, agreed to indemnify us until October 31, 2010 if certain contractual matters result in a claim, and agreed to indemnify us indefinitely for breaches of the agreement. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $680,000 and is subject to a maximum liability of $6.8 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

In connection with our acquisitions of East Texas and Discovery from DCP Midstream, LLC, DCP Midstream, LLC agreed to indemnify us until July 1, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing and that are associated with certain East Texas assets that were formerly owned by Gulf South and UP Fuels, and agreed to indemnify us indefinitely for breaches of the agreement and certain existing claims. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $2.7 million and is subject to a maximum liability of $27.0 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

In connection with our acquisition of certain subsidiaries of MEG, DCP Midstream, LLC agreed to indemnify us until August 29, 2008 for any breach of the representations and warranties (except certain corporate related matters that survive indefinitely), and indefinitely for breaches of the agreement.

We have not pursued indemnification under these agreements.

Other Agreements and Transactions with 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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. The 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, processing and other services to affiliates.

In addition, we sell NGLs processed at our Minden and Ada plants, and sell condensate removed from the gas gathering systems that deliver to the Minden and Ada plants, and from our Pelico system to a subsidiary of DCP Midstream, LLC equal to that subsidiary s net weighted-average sales price, adjusted for transportation, processing 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 also have a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze pipeline, pursuant to a fee-based rate that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a transportation agreement. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other 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 an NGL product dedication agreement with DCP Midstream, LLC. We generally report revenues, which are earned pursuant to a fee-based rate applied to the volumes transported on this pipeline, in the consolidated statements of operations as transportation, processing and other services to affiliates.

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

In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for certain Discovery capital projects, which were forecasted to be completed prior to our acquisition of a 40% limited liability company interest in Discovery. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $3.8 million and $0.3 million during 2008 and 2007, respectively to reimburse us for these capital projects, which were substantially completed in 2008.

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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 and $0.3 million during 2007, to reimburse us for the capital costs we incurred, primarily for growth capital projects.

In July 2008, DCP Midstream, LLC issued additional parental guarantees outside of the Omnibus Agreement, totaling $200.0 million, to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. These guarantees were reduced to $65.0 million as of December 31, 2008 to correspond with lower commodity prices and collateral requirements. We pay DCP Midstream, LLC interest of 0.5% per annum on these outstanding guarantees.

DCP Midstream, LLC was a significant customer during the years ended December 31, 2008, 2007 and 2006.

Duke Energy

Prior to December 31, 2006, we purchased natural gas from Duke Energy and its affiliates.

Spectra Energy

We purchase a portion of our propane from and market propane on behalf of Spectra Energy. We anticipate continuing to purchase propane from and market propane on behalf of Spectra Energy in the ordinary course of business.

During the second quarter of 2008, we entered into a propane supply agreement with Spectra Energy. This agreement, effective May 1, 2008 and terminating April 30, 2014, provides us propane supply at our marine terminal, which is included in our Wholesale Propane Logistics segment, for up to approximately 120 million gallons of propane annually. This contract replaces the supply provided under a contract with a third party that was terminated for non-performance during the first quarter of 2008.

ConocoPhillips

We have multiple agreements whereby we provide a variety of services to ConocoPhillips and its affiliates. The agreements include fee-based and percent-of-proceeds gathering and processing 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 $1.9 million, $2.9 million and $3.9 million of capital reimbursements during the years ended December 31, 2008, 2007 and 2006, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the transactions with affiliates:

	Year Ended December 31,		
	2008	2007	2006
		(Millions)	
DCP Midstream, LLC:			
Sales of natural gas, propane, NGLs and condensate	$ 475.7	$ 290.0	$ 231.7
Transportation, processing and other	$ 15.4	$ 6.0	$ 4.8
Purchases of natural gas, propane and NGLs	$ 175.3	$ 150.1	$ 102.9
(Losses) gains from derivative activity, net	$ (3.1)	$ (4.5)	$ 0.1
Operating and maintenance expense	$	$ 0.4	$ 0.2
General and administrative expense	$ 11.6	$ 10.0	$ 8.1
Interest expense	$ 0.4	$	$
Spectra Energy:			
Sales of natural gas, propane, NGLs and condensate	$ 0.3	$ 1.1	$
Transportation, processing and other	$ 0.2	$	$
Purchases of natural gas, propane and NGLs	$ 51.0	$	$
Duke Energy:			
Purchases of natural gas, propane and NGLs	$	$	$ 3.4
ConocoPhillips:			
Sales of natural gas, propane, NGLs and condensate	$ 1.8	$ 6.6	$ 1.1
Transportation, processing and other	$ 10.4	$ 10.6	$ 8.0
Purchases of natural gas, propane and NGLs	$ 36.6	$ 29.2	$ 12.9

We had accounts receivable and accounts payable with affiliates as follows:

	December 31,	
	2008	2007
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 30.3	$ 47.3
Accounts payable	$ 27.9	$ 53.3
Spectra Energy:		
Accounts receivable	$ 4.0	$ 1.5
Accounts payable	$ 5.3	$
ConocoPhillips:		
Accounts receivable	$ 2.5	$ 3.3
Accounts payable	$ 0.4	$ 2.3

The following summarizes the unrealized losses on derivative instruments with affiliates:

	December 31, 2008	December 31, 2007
	(Millions)	
DCP Midstream, LLC:		
Unrealized losses current	$ (1.2)	$ (2.7)

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:

	Depreciable Life	December 31, 2008	December 31, 2007
		(Millions)	
Gathering systems	15 30 Years	$ 405.0	$ 371.3
Processing plants	25 30 Years	163.4	91.4
Terminals	25 30 Years	28.5	24.2
Transportation	25 30 Years	174.0	141.0
General plant	3 5 Years	6.0	4.0
Construction work in progress		43.5	25.5
Property, plant and equipment		820.4	657.4
Accumulated depreciation		(191.1)	(156.7)
Property, plant and equipment, net		$ 629.3	$ 500.7

The above amounts include accrued capital expenditures of $12.3 million and $8.4 million as of December 31, 2008 and 2007, respectively, which are included in other current liabilities in the consolidated balance sheets.

Depreciation expense was $34.4 million, $23.3 million and $12.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

We lease one of our Michigan transmission pipelines to a third party under a long-term contract. The carrying value of the pipeline is approximately $23.0 million, with accumulated depreciation of $0.2 million. Minimum future non-cancelable rental payments are as follows:

	Rental Payments (Millions)
2009	$ 3.0
2010	2.9
2011	2.9
2012	2.8
2013	2.3
Thereafter	20.7
Total	$ 34.6

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 $7.9 million and $3.1 million at December 31, 2008 and 2007, respectively. The asset retirement obligation increased in 2008 and 2007, respectively, as a result of the MPP and MEG acquisitions. Accretion expense for the years ended December 31, 2008 and 2007 was $0.4 million and $0.1 million, respectively, and for the year ended December 31, 2006 was not significant.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines,

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

7. Goodwill and Intangible Assets

The change in the carrying amount of goodwill is as follows:

	December 31, 2008	December 31, 2007
	(Millions)	
Beginning of period	$ 80.2	$ 29.3
Acquisitions	8.6	50.9
End of period	$ 88.8	$ 80.2

Goodwill increased during 2008 by $6.7 million as a result of the MPP acquisition, and by $1.9 million for the final purchase price allocation for the MEG subsidiaries acquired from DCP Midstream, LLC. The increase in goodwill during 2007 represents the amount that we recognized in connection with our acquisition of the MEG subsidiaries from DCP Midstream, LLC.

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 tests indicated that our reporting unit s fair value exceeded its carrying or book value.

During the fourth quarter of 2008, as a result of the decline in the general equity market indices and in our unit price on the New York Stock exchange, we updated our fair value analysis using current marketplace assumptions and concluded that the carrying value of goodwill is recoverable; therefore, we did not record any impairment charges during the years ended December 31, 2008, 2007 and 2006. However, given the current volatility in the equity market, as well as volatile commodity prices, we will continue to monitor the recoverability of such amounts. Continued volatility and marketplace activity may alter our conclusion in the future, and could result in the recognition of an impairment charge.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31, 2008	December 31, 2007
	(Millions)	
Gross carrying amount	$ 52.5	$ 32.4
Accumulated amortization	(4.8)	(2.7)
Intangible assets, net	$ 47.7	$ 29.7

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Intangible assets increased in 2008 as a result of the MPP acquisition.

For the years ended December 31, 2008, 2007 and 2006, we recorded amortization expense of $2.1 million, $1.1 million and $0.4 million, respectively. As of December 31, 2008, the remaining amortization periods range from approximately less than one year to 25 years, with a weighted-average remaining period of approximately 21 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (Millions)
2009	$ 2.6
2010	2.6
2011	2.3
2012	2.3
2013	2.3
Thereafter	35.6
Total	$ 47.7

8. Equity Method Investments

The following table summarizes our equity method investments:

	Percentage of Ownership as of December 31, 2008 and 2007	Carrying Value as of December 31, 2008	Carrying Value as of December 31, 2007
		(Millions)	
Discovery Producer Services LLC	40%	$ 105.0	$ 117.9
DCP East Texas Holdings, LLC	25%	63.9	62.9
Black Lake Pipe Line Company	45%	6.3	6.2
Other	50%	0.2	0.2
Total equity method investments		$ 175.4	$ 187.2

Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana, a natural gas pipeline from offshore deep water in the Gulf of Mexico that transports gas to its processing plant in Larose, Louisiana with a design capacity of 600 MMcf/d and approximately 280 miles of pipe, and several laterals in the Gulf of Mexico. There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $39.7 million and $43.7 million at December 31, 2008 and 2007, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

East Texas is engaged in the business of gathering, transporting, treating, compressing, processing, and fractionating natural gas and NGLs. Its operations, located near Carthage, Texas, include a natural gas processing complex with a total capacity of 780 MMcf/d and a natural gas liquids fractionator. The facility is connected to an approximately 900-mile gathering system, as well as third party gathering systems. The complex includes and is adjacent to the Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 Bcf/d, acts as a key exchange point for the purchase and sale of residue gas.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $6.0 million and $6.4 million at December 31, 2008 and 2007, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

Earnings from equity method investments were as follows:

	Year Ended December 31,		
	2008	2007	2006
	(Millions)		
Discovery Producer Services LLC	$ 17.4	$ 24.1	$ 16.9
DCP East Texas Holdings, LLC	16.1	14.6	12.0
Black Lake Pipe Line Company and other	0.8	0.6	0.3
Total earnings from equity method investments	$ 34.3	$ 39.3	$ 29.2
Distributions from equity method investments	$ 59.9	$ 38.9	$ 25.9
Earnings from equity method investments, net of distributions	$ (25.6)	$ 0.4	$ 3.3

The following summarizes financial information of our equity method investments:

	Year Ended December 31,		
	2008	2007	2006
	(Millions)		
Statements of operations:			
Operating revenue	$ 792.7	$ 739.6	$ 686.9
Operating expenses	$ (696.9)	$ 634.6	$ 612.2
Net income	$ 99.8	$ 106.8	$ 77.4

	December 31,	
	2008	2007
	(Millions)	
Balance sheet:		
Current assets	$ 104.3	$ 168.8
Long-term assets	646.3	630.3

Current liabilities	(84.4)	(100.9)
Long-term liabilities	(22.4)	(14.9)
Net assets	$ 643.8	$ 683.3

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, as well as short-term and restricted investments, which are measured at fair value. Fair values are generally based upon quoted market prices, where available. In the event that listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an exit price methodology, in line with how we believe a marketplace participant would value that

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

asset or liability. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us.

Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 13 Risk Management Activities Credit Risk and Financial Instruments.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

Level 1 inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Level 2 inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 inputs are unobservable and considered significant to the fair value measurement.

A financial instrument s categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include over the counter, or OTC, instruments, such as natural gas, crude oil or NGL contracts.

Within our Natural Gas Services segment we typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. These instruments are generally classified as Level 2. Depending upon market conditions and our strategy, we may enter into OTC derivative positions with a significant time horizon to maturity, and market prices for these OTC derivatives may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

Within our Wholesale Propane Logistics segment, we may enter into a variety of financial instruments to either secure sales or purchase prices, or capture a variety of market opportunities. Since financial instruments for NGLs tend to be counterparty and location specific, we primarily use the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and a market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected correlation of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We have interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt, and are held with major financial institutions, which are expected to fully perform under the terms of our agreements. The swaps are generally priced based upon a United States Treasury instrument with similar duration, adjusted by the credit spread between our company and the United States Treasury instrument. Given that a significant portion of the swap

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit, our entity valuation, as well as liquidity reserves in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Short-Term and Restricted Investments

We are required to post collateral to secure the term loan portion of our credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated tax-exempt debt securities that have stated maturities of 20 years or more, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. Given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper and highly rated tax-exempt debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2. As of December 31, 2008, nearly all of our short-term and restricted investments were held in the form of money market securities. By virtue of our balances in these funds on September 19, 2008, all of these investments are eligible for, and the funds are participating in, the U.S. Treasury Department s Temporary Guarantee Program for Money Market Funds.

The following table presents the financial instruments carried at fair value as of December 31, 2008, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	Quoted Market Prices in Active Markets (Level 1)	Internal Models with Significant Observable Market Inputs (Level 2)	Internal Models with Significant Unobservable Market Inputs (Level 3)	Total Carrying Value
		(Millions)		
Current assets:				
Commodity derivative instruments(a)	$	$ 15.1	$ 0.3	$ 15.4
Long-term assets:				
Restricted investments	$	$ 60.2	$	$ 60.2
Commodity derivative instruments(b)	$	$ 6.9	$ 1.7	$ 8.6
Interest rate instruments(b)	$	$	$	$
Current liabilities(c):				
Commodity derivative instruments	$	$ (1.2)	$	$ (1.2)
Interest rate instruments	$	$ (16.5)	$	$ (16.5)
Long-term liabilities(d):				
Commodity derivative instruments	$	$ (3.2)	$	$ (3.2)

Interest rate instruments	$	$	(22.8)	$	$	(22.8)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.

(b) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.

(c) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.

(d) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheets.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in Level 3 Fair Value Measurements

The table below illustrates a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the Transfers In/Out of Level 3 caption.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

	Balance at December 31, 2007	Net Realized and Unrealized Gains Included in (Losses) Earnings	Transfers In/ Out of Level 3(a)	Purchases, Issuances and Settlements, Net	Balance at December 31, 2008	Net Unrealized Gains (Losses) Still Held Included in Earnings(b)
			(Millions)			
Commodity derivative instruments:						
Current assets	$ 0.2	$ 0.8	$	$ (0.7)	$ 0.3	$ 0.3
Long-term assets	$ 1.5	$ 1.0	$ (0.8)	$	$ 1.7	$ 1.0
Current liabilities	$ (1.6)	$ (0.2)	$	$ 1.8	$	$
Long-term liabilities	$ (0.2)	$ 0.2	$	$	$	$ 0.2

(a) Amounts transferred in are reflected at fair value as of the end of the period and amounts transferred out are reflected at fair value at the beginning of the period.

(b) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains (losses) relating to assets and liabilities classified as Level 3 that are still held at December 31, 2008.

10. Estimated Fair Value of Financial Instruments

We have determined 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 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 approximating market rates. Unrealized gains and unrealized losses on derivative 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Debt

Long-term debt was as follows:

	Principal Amount 2008	2007
	(Millions)	
Revolving credit facility, weighed-average interest rate of 2.08% and 5.47%, respectively, due June 21, 2012(a)	$ 596.5	$ 530.0
Term loan facility, interest rate 1.54% and 5.05%, respectively, due June 21, 2012(b)	60.0	100.0
Total long-term debt	$ 656.5	$ 630.0

(a) $575.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.26% to 5.19%, for a net effective rate of 4.48% on the $596.5 million of outstanding debt under our revolving credit facility as of December 31, 2008.

(b) The term loan facility is fully secured by restricted investments.

Credit Agreement

We have an $824.6 million 5-year credit agreement that matures June 21, 2012, or the Credit Agreement, which consists of:

a $764.6 million revolving credit facility; and

a $60.0 million term loan facility.

At December 31, 2008 and 2007, we had $0.3 million and $0.2 million of letters of credit issued under the credit agreement outstanding, respectively. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheet as of December 31, 2008 and 2007. As of December 31, 2008, the available capacity under the revolving credit facility was $171.5 million, which is net of approximately $21.7 million non-participation by Lehman Brothers Commercial Bank, or Lehman Brothers, as discussed below. We incurred $0.6 million of debt issuance costs during 2007 associated with the Credit Agreement. These expenses are deferred as other long-term assets in the consolidated balance sheet and will be amortized over the term of the Credit Agreement.

Under the Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank s prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our leverage level or credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to either: (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank s prime rate or the Federal Funds rate plus 0.50%.

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 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.5 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 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Lehman Brothers is a lender in our Credit Agreement. Lehman Brothers has not funded its portion of our borrowing requests since its bankruptcy, and it is uncertain whether it will participate in future borrowing requests. Accordingly, the availability of new borrowings under the Credit Agreement has been reduced by approximately $25.4 million as of December 31, 2008. Our borrowing capacity may be further limited by the Credit Agreement s financial covenant requirements. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the June 21, 2012 maturity date.

Bridge Loan

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provided for borrowings up to $100.0 million, and had terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100.0 million, which was due and payable no later than August 9, 2007.

We used borrowings on the Bridge Loan of $88.0 million to partially fund the Southern Oklahoma acquisition. The remaining $12.0 million available for borrowing on the Bridge Loan was not utilized. We used a portion of the net proceeds of a private placement of limited partner units to extinguish the $88.0 million outstanding on the Bridge Loan in June 2007.

Other Agreements

As of December 31, 2008, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million, which reduces the amount of cash we may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under our credit facility.

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.

In November 2007, our universal shelf registration statement on Form S-3 was declared effective by the SEC. The universal shelf registration statement has a maximum aggregate offering price of $1.5 billion, which will allow us to register and issue additional partnership units and debt obligations.

In June 2007, we entered into a private placement agreement with a group of institutional investors for $130.0 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $128.5 million, net of offering costs.

In July 2007, we issued 620,404 common units to DCP Midstream, LLC as partial consideration for the purchase of Discovery, East Texas and the Swap. In August 2007, we issued 275,735 common units to DCP Midstream, LLC as partial consideration for the purchase of certain subsidiaries of MEG.

In August 2007, we issued 2,380,952 common units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate.

In January 2008, our registration statement on Form S-3 to register the 3,005,780 common limited partner units represented in the June 2007 private placement agreement and the 2,380,952 common limited partner units represented in the August 2007 private placement agreement was declared effective by the SEC.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In March 2008, we issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of $132.1 million, net of offering costs.

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 Prior to June 2007, the general partner was 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 has not participated in certain issuances of common units. Therefore, the general partner s 2% interest has been diluted to approximately 1% as of December 31, 2008.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. The general partner s incentive distribution rights were not reduced as a result of these private placement agreements, and will not 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 current 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 On July 2, 2007, the Class C units were converted to 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 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 subordination period has an early termination provision that permits 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2008 and the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in the partnership agreement are satisfied. In 2008, we determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2008 and,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

therefore, 50% of the subordinated units, or 3,571,428 units, converted into common units. We determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2009 and, therefore, the remaining 3,571,429 units, converted into common units. Our board of directors and the conflicts committee of the board certified that all conditions for early conversion were satisfied. 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 Our partnership agreement, after adjustment for the general partner s relative ownership level, currently approximately 1%, requires that we make distributions of Available Cash for any quarter during the subordination period in the following manner:

first, to the common unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;

second, to the common unitholders and the general partner, in accordance with their pro rata interest, 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, to the subordinated unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;

fourth, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter (the First Target Distribution);

fifth, 13% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter (the Second Target Distribution);

sixth, 23% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter (the Third Target Distribution); and

thereafter, 48% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period Our partnership agreement, after adjustment for the general partner s relative ownership level, requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

first, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;

second, 13% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;

third, 23% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and

thereafter, 48% to the general partner, plus the general partner s pro rata interest, and the remainder to all unitholders.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents our cash distributions paid in 2008, 2007 and 2006:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
November 14, 2008	$ 0.600	$ 20.1
August 14, 2008	0.600	20.1
May 15, 2008	0.590	19.6
February 14, 2008	0.570	15.7
November 14, 2007	0.550	14.7
August 14, 2007	0.530	12.4
May 15, 2007	0.465	8.6
February 14, 2007	0.430	7.8
November 14, 2006	0.405	7.4
August 14, 2006	0.380	6.7
May 15, 2006	0.350	6.3
February 13, 2006(a)	0.095	1.7

(a) Represents 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.

13. Risk Management Activities, Credit Risk and Financial Instruments

The impact of our derivative activity on our results of operations and financial position is summarized below:

	Year Ended December 31, 2008	2007	2006
		(Millions)	
Commodity cash flow hedges:			
Losses due to ineffectiveness	$	$	$ (0.3)
(Losses) gains reclassified into earnings	$ (0.8)	$ 2.4	$ 2.6
Commodity derivative activity:			
Unrealized gains (losses) from derivative activity	$ 102.4	$ (81.7)	$ 0.3
Realized losses from derivative activity	$ (30.1)	$ (5.9)	$ (0.2)
Interest rate cash flow hedges:			
(Losses) gains reclassified into earnings	$ (6.7)	$ 0.7	$ 0.1

	December 31, 2008	December 31, 2007
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (1.8)	$ (2.6)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	$ (38.7)	$ (12.3)

For the years ended December 31, 2008, 2007 and 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.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 mitigate risks related to the variability of future 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.

As of December 31, 2007, we posted collateral with certain counterparties to our commodity derivative instruments of approximately $18.2 million, which is included in other current assets on the consolidated balance sheet. As of December 31, 2008, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million. This letter of credit reduces the amount of cash we may be required to post as collateral. As of December 31, 2008, we had no cash collateral posted with counterparties to our commodity derivative instruments.

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 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.

We manage our commodity derivative activities in accordance with our Risk Management Policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Interest Rate Risk Interest rates on credit facility balances 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,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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 Protection Activities We used NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGLs, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was accumulated in AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to the consolidated statements of operations in the same accounts as the item being hedged.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. Therefore, we are using the mark-to-market method of accounting for all commodity derivative instruments. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the underlying transactions impact earnings. As of December 31, 2008, deferred net losses of $0.9 million are expected to be reclassified during the next 12 months. Subsequent to July 1, 2007, the changes in fair value of financial derivatives are included in gains and losses from derivative activity in the consolidated statements of operations. The agreements are with major financial institutions, which management expects to fully perform under the terms of the agreements.

As of December 31, 2008, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with natural gas, NGLs and crude oil derivatives.

Other Asset-Based Activity 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 variability 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.

Commodity Fair Value Hedges Historically, we used fair value hedges to mitigate risk 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 cash flow exposure to fixed price risk by swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index-based).

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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the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of commodities in future periods as well as select operating expense contracts.

Interest Rate Cash Flow Hedges We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $575.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All 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. As of December 31, 2008, $16.0 million of deferred net losses 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. $425.0 million of the agreements reprice prospectively approximately every 90 days and the remaining $150.0 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 2.26% to 5.19%, 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

Total compensation (credit) cost for equity-based arrangements was as follows:

	Year Ended December 31,		
	2008	2007	2006
		(Millions)	
Performance Units	$ (0.7)	$ 1.1	$ 0.2
Phantom Units	(0.4)	0.6	0.4
Restricted Phantom Units	0.1		
Total compensation (credit) cost	$ (1.0)	$ 1.7	$ 0.6

On November 28, 2005, the board of directors of our General Partner adopted a long-term incentive plan, or 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 dividend equivalent rights, or 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 canceled or 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. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to directors in conjunction with our initial public offering, which are subject to graded vesting provisions.

All awards are accounted for as liability awards.

Performance Units We have awarded phantom LPUs, or Performance Units, pursuant to the LTIP to certain employees. Performance Units generally vest in their entirety at the end of a three year performance period. The number of Performance Units that will ultimately vest range from 0% to 200% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year

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performance periods. The final performance payout is determined by the compensation committee of the board of directors of our General Partner. The DERs will be paid in cash at the end of the performance period. Of the remaining Performance Units outstanding at December 31, 2008, 21,705 units vested in January 2009, 15,101 units are expected to vest on December 31, 2009, and 8,544 units are expected to vest on December 31, 2010.

At December 31, 2008, there was approximately $0.3 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 0.7 years. The following table presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2006		$	
Granted	40,560	$ 26.96	
Forfeited	(17,470)	$ 26.96	
Outstanding at December 31, 2006	23,090	$ 26.96	
Granted	29,610	$ 37.29	
Forfeited	(5,740)	$ 31.39	
Outstanding at December 31, 2007	46,960	$ 32.93	
Granted	17,085	$ 33.85	
Forfeited	(12,025)	$ 32.42	
Outstanding at December 31, 2008	52,020	$ 33.35	$ 9.40
Expected to vest(a)	45,350	$ 31.70	$ 9.40

(a) Based on our December 31, 2008 estimated achievement of specified performance targets, the performance target for units granted in 2008 is 100%, for units granted in 2007 is 102%, and for units granted in 2006 is 140.4%. The estimated forfeiture rate for units granted in 2008 and 2007 is 50%, and for units granted in 2006 is 0%.

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.

Phantom Units In conjunction with our initial public offering, in January 2006 our General Partner s board of directors awarded phantom LPUs, or Phantom Units, to key employees, and to directors who are not officers or employees of affiliates of the General Partner. The remaining Phantom Units outstanding at December 31, 2008 vested on January 3, 2009.

In 2007, we granted 4,500 Phantom Units, pursuant to the LTIP, to directors who are not officers or employees of affiliates of the General Partner as part of their annual director fees for 2007. Of these units, 4,000 units vested during 2007 and 500 units vested in February 2008.

In 2008, we granted 4,000 Phantom Units, pursuant to the LTIP, to directors who are not officers or employees of affiliates of the General Partner as part of their annual director fees for 2008. All of these units vested during 2008.

The DERs are paid quarterly in arrears.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2006		$	
Granted	35,900	$ 24.05	
Forfeited	(11,200)	$ 24.05	
Outstanding at December 31, 2006	24,700	$ 24.05	
Granted	4,500	$ 42.90	
Forfeited	(2,333)	$ 24.05	
Vested	(6,668)	$ 35.23	
Outstanding at December 31, 2007	20,199	$ 24.56	
Granted	4,000	$ 35.88	
Forfeited	(4,000)	$ 24.05	
Vested	(6,501)	$ 32.91	
Outstanding at December 31, 2008	13,698	$ 24.05	$ 9.40
Expected to vest	13,698	$ 24.05	$ 9.40

The estimate of Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate.

Restricted Phantom Units Our General Partner s board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. The RPUs outstanding at December 31, 2008 are expected to vest on December 31, 2011. The DERs are paid quarterly in arrears.

At December 31, 2008, there was approximately $0.2 million of unrecognized compensation expense related to the RPUs that is expected to be recognized over a weighted-average period of 2.0 years. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit

Outstanding at January 1, 2008		$		$	
Granted	17,085	$	33.85		
Forfeited	(2,395)	$	35.88		
Vested		$			
Outstanding at December 31, 2008	14,690	$	33.52	$	9.40
Expected to vest	8,544	$	33.85	$	9.40

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate, which was estimated at 50% as of December 31, 2008. 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 certain awards issued under the LTIP in cash upon vesting. Compensation expense on these awards is recognized ratably over each vesting period, and will be remeasured each reporting period for

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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.

15. Income Taxes

We are structured as a master limited partnership, which is a pass-through entity for federal income tax purposes. Accordingly, we had no deferred tax balances as of December 31, 2008, 2007 and 2006, and no federal income tax expense for the years ended December 31, 2008, 2007 and 2006.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded current tax expense for the Texas margin tax beginning in 2007. During 2008 we acquired properties in Michigan. Michigan imposes a business tax of 0.8% on gross receipts, and 4.95% of Michigan taxable income. The sum of the gross receipts and income tax is subject to a tax surcharge of 21.99%. Michigan provides tax credits that may reduce our final tax liability.

Income tax expense for the years ended December 31, 2008 and 2007, consisted of current expense of $0.1 million for both periods, related primarily to the Texas margin tax. We did not have income tax expense in 2006. Our effective tax rate differs from statutory rates, primarily due to being structured as a limited partnership, which is a pass-through entity for United States income tax purposes, while being treated as a taxable entity in certain states.

16. Net Income or Loss per Limited Partner Unit

Our net income or loss 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 income or loss allocated to predecessor operations and incentive distributions paid to the general partner.

Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic earnings per unit using the two-class method. 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.

These required disclosures do not impact our overall net income or loss 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 LPU. 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, there is no impact on our calculation of earnings per LPU. During the year ended December 31, 2008, our aggregate net income per limited partner unit exceeded the Fourth Target Distribution level, and as a result we allocated an additional $24.8 million in additional earnings to the general partner. During the year ended December 31, 2007, no additional earnings were allocated to the general partner. 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 or loss per LPU is calculated by dividing limited partners interest in net income or loss, less pro forma general partner incentive distributions as described above, by the weighted-average number of outstanding LPUs during the period.

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The following table illustrates our calculation of net income per LPU:

	Year Ended December 31, 2008	2007 (Millions)	2006
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Less:			
Net income attributable to predecessor operations		(3.6)	(26.6)
Net income (loss) attributable to the partnership	125.7	(19.4)	35.3
Less: General partner interest in net income	(11.9)	(2.2)	(0.7)
Limited partners interest in net income or net loss	113.8	(21.6)	34.6
Less: Additional earnings allocation to general partner	(24.8)		(1.3)
Net income (loss) available to limited partners	$ 89.0	$ (21.6)	$ 33.3
Net income (loss) per LPU basic and diluted	$ 3.25	$ (1.05)	$ 1.90

17. Commitments and Contingent Liabilities

Litigation

Driver In August 2007, Driver Pipeline Company, Inc., or Driver, filed a lawsuit against DCP Midstream, LP, an affiliate of the owner of our general partner, in District Court, Jackson County, Texas. The litigation stems from an ongoing commercial dispute involving the construction of our Wilbreeze pipeline, which was completed in December 2006. Driver was the primary contractor for construction of the pipeline and the construction process was managed for us by DCP Midstream, LP. Driver claims damages in the amount of $2.4 million for breach of contract. We believe Driver s position in this litigation is without merit and we intend to vigorously defend ourselves against this claim. 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.

El Paso On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved a contingent liability of $2.5 million for this matter, which is included in our consolidated financial statements for the year ended December 31, 2008.

Other We are not a party to any other significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes 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 on our consolidated results of operations, financial position, or cash flows.

Insurance We contract with a third party insurer for our primary general liability insurance covering third party exposures. DCP Midstream, LLC provides our remaining insurance coverage through third party insurers for: (1) statutory workers compensation insurance; (2) automobile liability insurance for all owned,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

non-owned and hired vehicles; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) property insurance, which covers replacement value of all real and personal property and includes business interruption/ extra expense and (5) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

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 certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors. See the Indemnification section of Note 5 for additional details.

Other Commitments and Contingencies We utilize assets under operating leases in several areas of operation. Consolidated rental expense, including leases with no continuing commitment, totaled $12.9 million, $11.4 million and $11.2 million for the years ended December 31, 2008, 2007 and 2006, 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, 2008:

		(Millions)
2009	$	12.4
2010		9.0
2011		7.9
2012		7.0
2013		5.8
Thereafter		2.6
Total minimum rental payments	$	44.7

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 (1) our Northern Louisiana natural gas gathering, processing and transportation system; (2) our Southern Oklahoma system, acquired in May 2007; (3) our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and the Swap, acquired in July 2007; (4) our Colorado and Wyoming systems, acquired in August 2007; and (5) our Michigan systems, acquired in October 2008.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Wholesale Propane Logistics The Wholesale Propane Logistics segment consists of six owned rail terminals, one of which was idled in 2007 to consolidate our operations, one leased marine terminal, one pipeline terminal and access to several open access pipeline terminals.

NGL Logistics The NGL Logistics segment consists of the Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline. Prior to December 7, 2005, our equity interest was 50%. 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. The Wilbreeze transportation pipeline began operations in December 2006.

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 following tables set forth our segment information:

Year Ended December 31, 2008:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics (Millions)	Other(c)	Total
Total operating revenue	$ 791.5	$ 483.0	$ 11.3	$	$ 1,285.8
Gross margin(a)	$ 206.5	$ 11.0	$ 7.1	$	$ 224.6
Operating and maintenance expense	(32.1)	(9.9)	(1.0)		(43.0)
Depreciation and amortization expense	(33.8)	(1.3)	(1.4)		(36.5)
General and administrative expense				(24.0)	(24.0)
Other		1.5			1.5
Earnings from equity method investments	33.5		0.8		34.3
Interest income				5.6	5.6
Interest expense				(32.8)	(32.8)
Income tax expense(b)				(0.1)	(0.1)
Non-controlling interest in income	(3.9)				(3.9)
Net income (loss)	$ 170.2	$ 1.3	$ 5.5	$ (51.3)	$ 125.7
Non-cash derivative mark-to-market(d)	$ 99.2	$ 2.4	$	$ (0.6)	$ 101.0
Capital expenditures	$ 36.6	$ 3.3	$ 0.4	$ 0.7	$ 41.0

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Year Ended December 31, 2007:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
		(Millions)			
Total operating revenue	$ 404.1	$ 459.6	$ 9.6	$	$ 873.3
Gross margin(a)	$ 16.2	$ 25.5	$ 4.9	$	$ 46.6
Operating and maintenance expense	(20.9)	(10.4)	(0.8)		(32.1)
Depreciation and amortization expense	(21.9)	(1.1)	(1.4)		(24.4)
General and administrative expense				(24.1)	(24.1)
Earnings from equity method investments	38.7		0.6		39.3
Interest income				5.3	5.3
Interest expense				(25.8)	(25.8)
Income tax expense(b)				(0.1)	(0.1)
Non-controlling interest in income	(0.5)				(0.5)
Net income (loss)	$ 11.6	$ 14.0	$ 3.3	$ (44.7)	$ (15.8)
Non-cash derivative mark-to-market(d)	$ (78.3)	$ (2.8)	$	$	$ (81.1)
Capital expenditures	$ 16.2	$ 3.9	$ 1.2	$	$ 21.3

Year Ended December 31, 2006:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
		(Millions)			
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				(21.0)	(21.0)
Earnings from equity method investments	28.9		0.3		29.2

Interest income								6.3		6.3
Interest expense								(11.5)		(11.5)
Net income (loss)	$	79.6	$	6.6	$	1.9	$	(26.2)	$	61.9
Non-cash derivative mark-to-market(d)	$	0.1	$		$		$		$	0.1
Capital expenditures	$	6.5	$	9.4	$	11.3	$		$	27.2

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2008	December 31, 2007
	(Millions)	
Segment long-term assets:		
Natural Gas Services(e)	$ 856.4	$ 710.7
Wholesale Propane Logistics	54.3	52.6
NGL Logistics	33.8	34.8
Other(f)	70.3	104.1
Total long-term assets	1,014.8	902.2
Current assets	165.2	218.5
Total assets	$ 1,180.0	$ 1,120.7

(a) Gross margin consists of total operating revenues, including commodity derivative activity, 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 in 2008 and 2007 relates primarily to the Texas margin tax.

(c) Other consists of general and administrative expense, interest income, interest expense and income tax expense.

(d) Non-cash derivative mark-to-market is included in segment gross margin, along with cash settlements for our derivative contracts.

(e) Long-term assets for our Natural Gas Services segment increased in 2008 as a result of our acquisition of MPP in October 2008, and in 2007 as a result of our Southern Oklahoma acquisition in May 2007, and our acquisition of certain MEG subsidiaries in August 2007. Long-term assets for our Natural Gas Services segment include the effects of our 25% equity interest in East Texas, our 40% equity interest in Discovery and the Swap acquired in July 2007, for all periods presented.

(f) Other long-term assets not allocable to segments consist of restricted investments, unrealized gains on derivative instruments, corporate leasehold improvements and other long-term assets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. Supplemental Cash Flow Information

	Year Ended December 31, 2008	2007 (Millions)	2006
Cash paid for interest:			
Cash paid for interest, net of amounts capitalized	$ 26.3	$ 26.5	$ 11.1
Non-cash investing and financing activities:			
Non-cash additions of property, plant and equipment	$ 1.5	$ 5.9	$ 1.4
Accounts payable related to acquisitions	$	$ 9.0	$ 9.9
Accrued distributions to DCP Midstream, LLC related to reimbursements	$	$ 0.5	$
Accrued contributions from DCP Midstream, LLC related to reimbursements	$	$ 0.3	$
Accrued equity-based compensation	$ 0.2	$ 0.2	$

20. Quarterly Financial Data (Unaudited)

Our consolidated results of operations by quarter for the years ended December 31, 2008, 2007 and 2006 were as follows (millions, except per unit amounts):

2008	First	Second	Third	Fourth	Year Ended December 31, 2008
Total operating revenues	$ 337.7	$ 145.9	$ 426.8	$ 375.4	$ 1,285.8
Operating (loss) income	$ (16.6)	$ (165.7)	$ 152.4	$ 152.5	$ 122.6
Net (loss) income	$ (6.5)	$ (159.3)	$ 152.7	$ 138.8	$ 125.7
Limited partners interest in net (loss) income	$ (8.2)	$ (159.8)	$ 147.8	$ 134.0	$ 113.8
Basic net (loss) income per limited partner unit	$ (0.33)	$ (5.66)	$ 2.97	$ 2.72	$ 3.25

2007	First	Second	Third	Fourth	Year Ended December 31, 2007
Total operating revenues	$ 237.2	$ 181.1	$ 188.6	$ 266.4	$ 873.3
Operating income (loss)	$ 11.5	$ (1.8)	$ 3.9	$ (47.6)	$ (34.0)
Net income (loss)	$ 15.8	$ 0.8	$ 7.5	$ (39.9)	$ (15.8)
Limited partners interest in net income (loss)(a)	$ 12.2	$ 0.2	$ 6.6	$ (40.6)	$ (21.6)
Basic net income (loss) per limited partner unit(a)	$ 0.58	$ 0.01	$ 0.29	$ (1.69)	$ (1.05)

2006	First	Second	Third	Fourth	Year Ended December 31, 2006
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	$ 16.3	$ 15.7	$ 14.3	$ 15.6	$ 61.9
Limited partners interest in net income(a)(b)	$ 5.3	$ 8.6	$ 9.5	$ 11.1	$ 34.6
Basic net income per limited partner unit(a)(b)	$ 0.30	$ 0.47	$ 0.51	$ 0.55	$ 1.90

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) Total limited partners interest in net income and basic income per limited partner unit excludes the results from our interest in East Texas, Discovery and the Swap for the period January 1, 2006 through June 30, 2007.

(b) 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.

21. Subsequent Events

On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved a contingent liability of $2.5 million for this matter, which is included in our consolidated financial statements for the year ended December 31, 2008.

On February 25, 2009, we entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC will contribute an additional 25.1% interest in East Texas to us in exchange for 3.5 million Class D units, providing us with a 50.1% interest in East Texas following the expected closing of the transaction in April 2009. This closing date is subject to extension for up to 45 days to allow for repairs or replacement to our reasonable satisfaction any assets destroyed or damaged by certain casualty losses and time to enable the plant to process all available inlet volumes as defined in the Contribution Agreement. The Class D units will automatically convert into common units in August 2009 and will not be eligible to receive a distribution until the second quarter distribution payable in August 2009. DCP Midstream, LLC has agreed to provide a fixed-price NGL derivative by NGL component for the period of April 2009 to March 2010 for the acquired interest. Subsequent to this transaction, we will consolidate East Texas in our consolidated financial statements.

On February 11, 2009, we announced, along with DCP Midstream, LLC, that our East Texas natural gas processing complex and residue natural gas delivery system known as the Carthage Hub, have been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. No employees or contractors were injured in the incident. There was no significant damage to the natural gas processing complex. As of February 25, 2009, the complex began processing through one of the five plants, and it is expected that full processing capacities will be restored for the entire complex over the next 30 days. Residue gas will be redelivered into limited available pipeline interconnects while the Carthage Hub undergoes inspection and repairs.

On February 17, 2009, the remaining 3,571,429 DCP Partners subordinated units were converted to common units following the completion of the subordination period and satisfactory completion of all subordination period tests contained in the DCP Partners partnership agreement.

In February 2009, we entered into interest rate swap agreements to convert $275.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to interest rate fluctuations. These interest rate swaps commence in December 2010 and expire in June 2012

On January 27, 2009, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on February 13, 2009 to unitholders of record on February 6, 2009.

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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, 2008.

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, 2008, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of December 31, 2008, our disclosure controls and procedures were effective. There were no 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 2008 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, 2008 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, 2008.

Deloitte & Touche, LLP, an independent registered public accounting firm, has issued their report, included immediately following, regarding our internal control over financial reporting.

March 4, 2009

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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 internal control over financial reporting of DCP Midstream Partners, LP and subsidiaries (the Company) as of December 31, 2008, 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, included in the accompanying Management s Annual Report On Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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.

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In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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, 2008 of the Company and our report dated March 4, 2009 expressed an unqualified opinion (including explanatory paragraphs referring to (1) the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to the wholesale propane logistics business from the separate records maintained by DCP Midstream, LLC and (2) the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to the DCP East Texas Holdings, LLC, Discovery Producer Services, LLC, and a nontrading derivative instrument from the separate records maintained by DCP Midstream, LLC) on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP
Denver, Colorado
March 4, 2009

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, 2008.

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 nine members, four 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 four 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, except Mark A. Borer, our CEO and President, who devotes more than 90% of his 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, during 2008. In addition, directors are expected to be prepared for each meeting of the board by reviewing materials distributed in advance.

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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
Thomas C. O Connor	53	Chairman of the Board and Director
Mark A. Borer	54	President, Chief Executive Officer and Director
Angela A. Minas	44	Vice President and Chief Financial Officer
Michael S. Richards	49	Vice President, General Counsel and Secretary
Don Baldridge	39	Vice President, Business Development
Paul F. Ferguson, Jr.	59	Director
Gregory J. Goff	52	Director
Alan N. Harris	55	Director
John E. Lowe	50	Director
Frank A. McPherson	75	Director
Thomas C. Morris	68	Director
Stephen R. Springer	62	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.

Thomas C. O Connor was elected Chairman of the Board of DCP Midstream GP, LLC in September 2008, and has been a director of DCP Midstream GP, LLC since December 2007. Mr. O Connor has over 20 years experience in the natural gas industry with Duke Energy prior to joining DCP Midstream, LLC in November 2007 as Chairman of the board, President and CEO. Mr. O Connor joined Duke Energy in 1987 where he served in a variety of positions in the company s natural gas and pipeline operations units. After serving in a number of leadership positions with Duke Energy, he was named President and Chief Executive Officer of Duke Energy Gas Transmission in 2002 and he was named Group Vice President of corporate strategy at Duke Energy in 2005. In 2006 he became Group Executive and Chief Operating Officer of U.S. Franchised Electric and Gas and later in 2006 was named Group Executive and President of Commercial Businesses at Duke Energy.

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.

Angela A. Minas was elected Vice President and Chief Financial Officer of DCP Midstream GP, LLC in September 2008. Ms. Minas was previously Chief Financial Officer, Chief Accounting Officer and Treasurer for Constellation Energy Partners from September 2006 through March 2008. She also served as Managing Director of the Commodities Group at Constellation Energy Group, Inc. from September 2006 through March 2008. Prior to that, Ms. Minas was Senior Vice President, Global Consulting from 2004 to 2006 for SAIC and Vice President, US Consulting from 2002 to 2003 for SAIC. Prior to that, Ms. Minas was a partner with Arthur Andersen LLP from 1997 through 2002.

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.

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Don Baldridge was elected Vice President, Business Development of DCP Midstream GP, LLC in January 2009. Mr. Baldridge was previously Vice President, Corporate Development of DCP Midstream, LLC since August 2008. Prior to that, he served as senior director, corporate development and other management positions with DCP Midstream, LLC since April 2005. Mr. Baldridge has more than 16 years experience in the energy industry, including commercial, trading and business development activities.

Paul F. Ferguson, Jr. was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Ferguson was a member of the Compensation, Audit and special committees of the general partner of TEPPCO Partners, L.P. 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. Mr. Ferguson was a director of the general partner of TEPPCO Partners, L.P. from October 2004 until his resignation in 2005.

Gregory J. Goff, was elected a director of DCP Midstream GP, LLC in October 2008, and is currently Senior Vice President, Commercial for ConocoPhillips. Previously, Mr. Goff served as President, Specialty Businesses and Business Development. From 2004 to 2006, Mr. Goff served as president of ConocoPhillips US Lower 48 and Latin American exploration and production business. From 2002 to 2004 Mr. Goff served as president of Europe and Asia Pacific Downstream Activities for ConocoPhillips. From 2000 to 2002 Mr. Goff served as Chairman and Managing Director of Conoco Limited in the United Kingdom. From 1998 to 2000 Mr. Goff served as managing Director and Chief Executive Officer of Conoco JET Nordic in Stockholm, Sweden.

Alan N. Harris was appointed as a director of DCP Midstream GP, LLC in December 2008, effective January 1, 2009; at that time he was not appointed to any committee of the board of Directors. In January 2009, the board of directors appointed Mr. Harris as Chairman to the compensation committee of the board of directors. Mr. Harris currently serves as chief development and operations officer of Spectra Energy. Prior to Spectra Energy s spin-off from Duke Energy in 2007, Mr. Harris served as group vice president and chief financial officer of Duke Energy Gas Transmission, or DEGT, from February 2004 and was named executive vice president of DEGT in December 2002. Mr. Harris, who joined the corporation in 1982, has served in a number of other senior management positions since that time. Mr. Harris has been in the energy industry for over 30 years.

John E. Lowe, was elected a director of DCP Midstream GP, LLC in October 2008, and is currently Assistant to the Chief Executive Officer for ConocoPhillips, representing the company in external relationships and assisting on special projects. Mr. Lowe was previously Executive Vice President, Exploration and Production. Mr. Lowe has also served ConocoPhillips as Executive Vice President of Planning, Strategy and Corporate Affairs. Senior Vice President of Corporate Strategy and Development and was responsible for the forward strategy, development opportunities and public relations functions of Phillips Petroleum Company. From 1999 to 2000, Mr. Lowe served as Vice President of Planning and Strategic Transactions for ConocoPhillips.

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 previously served on the boards of Integris Health, Tri Continental Corporation, Seligman Group of Mutual Funds, ConocoPhillips, Kimberly Clark Corporation, MAPCO Inc., Bank of Oklahoma, the Federal Reserve Bank of Kansas City, the Oklahoma State University Foundation Board of Trustees, the American Petroleum Institute, and several non-profit organizations in Oklahoma.

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

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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.

Stephen R. Springer was elected as a director of DCP Midstream GP, LLC in July 2007. Mr. Springer has over thirty years experience in the energy industry. He began his career at Texas Gas Transmission Corporation, where he served in a variety of executive management positions within gas acquisitions and gas marketing. After serving as President of Transco Gas Marketing Company, he served as Vice President of Business Development at Williams Field Services Company and then Senior Vice President and General Manager of Williams Midstream Division, the position he held until his retirement in 2002. Mr. Springer has served on the board of directors of Atmos Energy Corporation since 2005.

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 Securities and Exchange Commission, or 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, 2008, all Section 16(a) filing requirements applicable to such reporting persons were complied with, except that a late Form 4 was filed for Ms. Minas in January 2009 reflecting the granted phantom units dated October 1, 2008, following her employment by the Partnership.

Audit Committee

The board of directors of our General Partner has a standing audit committee. The audit committee is composed of four nonmanagement directors, Paul F. Ferguson, Jr. (chairman), Frank A. McPherson, Thomas C. Morris and Stephen R. Springer, 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 407(d) 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.

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Special Committee

The board of directors of our General Partner has a standing special committee, which is comprised of four nonmanagement directors, Stephen R. Springer (chairman), Paul F. Ferguson, Jr., Frank A. McPherson 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 meets at each quarterly meeting of the Board of Directors. 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, Alan N. Harris (chairman), Gregory J. Goff, Thomas C. O Connor 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.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of the special committee, the committee, which consists of all of our non-management directors, meets in an executive session without management participation or participation by non-independent directors. The chairman of the special committee presides over these executive sessions.

Unitholders or interested parties may communicate with any and all members of our board, including our nonmanagement directors, or any committee of our board, 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, (303) 633-2921.

New York Stock Exchange, or NYSE, Annual Certification

On March 26, 2008, Mark A. Borer, our Chief Executive Officer, certified to the NYSE, as required by NYSE rules, that as of March 26, 2008, 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, 2008, 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
Stephen R. Springer

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.

As of February 23, 2009, our General Partner has four executive officers and six additional employees. All of these employees are solely dedicated to our operations and management, except our President and Chief Executive Officer, or CEO, who devotes more than 90% of his time 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 has four members as of February 23, 2009. The compensation committee s responsibilities include, among other duties, the following:

- annually review and approve Partnership goals and objectives relevant to compensation of the CEO and other executive officers;

- annually evaluate the CEO s performance in light of the Partnership goals and objectives, and approve the compensation levels for the CEO and other executive officers;

- 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;

- 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 or in similar lines of business;

- Motivate executive officers and key management 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.

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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 2008 we engaged the services of BDO Seidman, LLP, or BDO, 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 2008 Towers Perrin General Industry Executive Compensation Database, or the Towers Perrin Database. The study was comprised of the following peer companies: Boardwalk Pipeline Partners, LP, Buckeye Partners, L.P., Copano Energy, L.L.C., Crosstex Energy, L.P., Enbridge Energy Partners, L.P., Genesis Energy, L.P., Magellan Midstream Partners, L.P., MarkWest Energy Partners, L.P., NuStar Energy L.P., ONEOK Partners, L.P., Plains All American Pipeline, L.P., Regency Energy Partners LP, Spectra Energy Partners, LP, Sunoco Logistics Partners L.P., Targa Resources Partners LP and TEPPCO Partners LP. Studies such as this generally include only the most highly compensated officers of each company, which correlates with 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 BDO study and the data point that represents the 50th 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 cash settled 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 2008, this allocation for targeted compensation of our executive officers was as follows:

	Base Salary	**Targeted STI Level**	**Targeted LTIP Level**
CEO	34%	21%	45%
Chief Financial Officer, or CFO	44%	20%	36%
Vice Presidents	44%	20%	36%

In allocating compensation among these components, we believe a significant portion of the compensation of our executive officers should be performance-based since these individuals have a greater opportunity to influence our performance. In making this allocation, we have relied in part on the BDO 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 BDO 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 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 our performance objectives. 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

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markets when target performance is achieved, below the market median when performance is less than target and above the market median when performance exceeds target. The BDO 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 2008, 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 and ultimately by the full board of directors. In 2008, the STI objectives approved by the compensation committee were divided as follows: (1) company objectives accounted for 75% of the STI and (2) personal objectives accounted for 25% of the STI. The target incentive opportunities for 2008 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 2008 stated company objectives under the STI were based on the following and were weighted as indicated:

1) The achievement of our budget for operating cash flow from our 2008 budgeted asset base, excluding the impact from non-cash mark to market adjustments to derivative instruments and any one-time transaction costs. We define operating cash flow as our distributable cash flow plus maintenance capital and interest expense. As a publicly traded limited partnership, our performance is generally judged on our ability to pay cash distributions to our unitholders. Distributable cash flow has three primary components: maintenance capital, interest expense and operating cash flow. We use operating cash flow as the financial objective because we believe it is the most controllable component of distributable cash flow and permits management to focus on the long term sustainability and development of our assets. For this company objective, the target level of performance is operating cash flow of $118.0 million, the maximum level of performance is operating cash flow of $135.0 million and the minimum level of performance operating cash flow of $110.0 million. The weighting of this objective relative to the other stated company objectives was 35%.

2) Deliver on board approved 2008 growth capital including acquisitions, organic growth projects and the dropdown of assets from our sponsors. We believe that our performance is also judged by our growth, which can translate into distribution growth. For this company objective, the target level of performance is $400.0 million of approved growth capital in 2008, the maximum level of performance is $900.0 million of approved growth capital in 2008 and the minimum level of performance is $250.0 million of approved growth capital in 2008. The weighting of this objective relative to the other stated company objectives was 25%.

3) Establishing and maintaining strong internal controls and accounting accuracy while meeting the performance requirements of the Sarbanes-Oxley Act of 2002. For this company objective, the minimum level of performance will be based on having no material weaknesses identified by management or the external auditor. A subjective determination will be made by the Audit Committee to assess performance between the minimum and maximum level of performance taking into consideration the number of significant deficiencies identified. The weighting of this objective relative to the other stated company objectives was 7%.

4) A safety objective based on recordable incident rate, or RIR, of both our assets and the assets of DCP Midstream, LLC, the owner of our general partner and the operator or our assets. If a fatality occurs of our employee or that of our contractor on our premises, a 5% safety penalty will be assessed against the entire STI payout. For this company objective, the target level of performance is an RIR of 0.75, the maximum level of performance is an RIR of 0.40 and the minimum level of performance is an RIR of

0.95. The weighting of this objective relative to the other stated company objectives was 5%.

5) An environmental objective of non-routine air emissions, natural gas vented or flared, of both our assets and the assets of DCP Midstream, LLC. For this company objective, the target level of

performance is 1,000 million standard cubic feet, or MMscf, the maximum level of performance is 790 MMscf and the minimum level of performance is 1,200 MMscf. The weighting of this objective relative to the other stated company objectives was 3%.

The payout on these company objectives ranged from 0% if the minimum level of performance was not achieved, 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. The level of performance achieved for each objective was as follows:

STI Objective	Level of Performance Achieved
1) Operating cash flow	Between Minimum and Target
2) Growth capital	Between Minimum and Target
3) Internal controls	Target
4) Safety	Between Minimum and Target
5) Environmental	Below Minimum No Payout

For fiscal year 2008, the compensation committee and the board of directors adjusted the actual payout on the company objectives downward to 50% of target. In making this adjustment, we considered the current economic challenges created by the U.S. and global recession, the performance of the Partnership s publicly traded equity and the operational challenges that were encountered by the Partnership in 2008. Taking all of these factors into consideration, we felt that it was prudent to reduce the annual cash incentives of management for these company objectives. As a result of this adjustment, the aggregate level of payout achieved for the above company objectives will be 50% of target.

The 2008 stated personal objectives under the STI were based on a number of individual performance objectives for each employee, which included items such as distribution growth, maintenance of strong liquidity in the debt and equity capital markets, and execution of our growth strategies. 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, 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 2008, the compensation committee and the board of directors adjusted downward the actual payout on these personal objectives as a result of the U.S. and global recessions, the performance of the Partnership s publicly traded equity and the operational challenges that were encountered by the Partnership in 2008. As a result of these adjustments, the aggregate level of payout achieved by the executive officers as a group on their personal objectives will be 54.5% of target.

As a result of the adjustments recommended by the compensation committee and ratified by the board of directors discussed above regarding the company objectives and the personal objectives, the total payout for the executive officers under the STI for fiscal year 2008 ranged from 37.5% to 65.5% of target, with the CEO at 37.5%.

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 LTIP program, we issued phantom limited partner units to each executive officer. Half of such phantom units are performance phantom units, or PPUs, and half are restricted phantom units, or RPUs. The PPUs will vest based upon the level of achievement of certain performance objectives over a three year performance period, or the Performance Period. The RPUs will automatically vest if the executive officer remains employed with us at the end of a three year vesting period, or the Vesting Period. We believe this program promotes retention of our executive officers, and focuses our executive officers on the goal of long-term value creation.

For 2008, the PPUs have as a performance measurement total shareholder return over the Performance Period relative to a peer group of 31 other similar public limited partnerships that we believe that we compete with in the capital markets. The companies included in this peer group at the start of 2008 were the following: Atlas Pipeline Partners LP, Boardwalk Pipeline Partners LP, Buckeye Partners L P, Copano Energy, L.L.C., Crosstex Energy LP, Duncan Energy Partners L.P., Eagle Rock Energy Partners L P, El Paso Pipeline Partners, L.P., Enbridge Energy Partners LP, Energy Transfer Partners, L.P., Enterprise Products Partners L P, Genesis Energy LP, Global Partners LP, Hiland Partners, LP, Holly Energy Partners LP, Kinder Morgan Energy Partners LP, Magellan Midstream Partners LP, MarkWest Energy Partners LP, NuStar Energy L.P., ONEOK Partners LP, Plains All American Pipeline LP, Quicksilver Gas Services LP, Regency Energy Partners LP, Semgroup Energy Partners, L.P., Spectra Energy Partners, LP, Sunoco Logistics Partners LP, Targa Resources Partners LP, TC Pipelines LP, TEPPCO Partners LP, TransMontaigne Partners L.P. and Williams Partners L.P. If a company originally named to the peer group is not publicly traded at the end of the Performance Period, none of its performance will be used in calculating the peer group s total shareholder return. If there is a combination of any peer group companies during the Performance Period, the performance of the surviving entity will be used. No new companies will be added to the peer group during the Performance Period.

For 2008, the RPUs will vest automatically at the end of the Vesting Period provided the executive officer remains employed with us at the end of such period.

These PPU and RPU awards were granted at the first regular board of directors meeting during the first quarter of 2008. 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 dividend equivalent rights, or DERs, on the number of units earned during the Vesting Period. The DERs on the PPUs will be paid in cash at the end of the Performance Period and the DERs on the RPUs will be paid quarterly in cash during the Vesting Period. The amount paid on the DERs will equal the quarterly distributions actually paid during the Performance Period and the Vesting Period on the number of PPUs or RPUs earned.

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 PPUs and RPUs 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 BDO study data for individuals in comparable positions. The target 2008 long-term incentive opportunities, expressed as a percentage of base salary, for the CEO, the CFO and the Vice Presidents were 130%, 80% and 80%, respectively.

For the PPUs granted in 2008, the performance measure is total shareholder return over the Performance Period relative to the peer group described above. 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 and ultimately by the full board of directors. The compensation committee believes utilizing total shareholder return as a performance measure provides incentive for the continued growth of our operating footprint and distributions to unitholders. This performance measure, coupled with the 2008 STI objectives to meet or exceed operating cash flow targets, provides management with appropriate incentives for our disciplined and steady growth. If our total shareholder return ranking among the 31 companies listed in our peer group over the Performance Period is less than the 30th percentile, 0% of the PPUs will vest. If such ranking over the Performance Period is in the 30th percentile, 50% percent of the PPUs will vest. If such ranking over the Performance Period is in the 50th percentile, 100% of the PPUs will vest and if such ranking over the Performance Period is in the 90th percentile, 200% of the PPUs will vest. Total shareholder return will be based on data obtained from Bloomberg and assumes that any dividends or distributions are reinvested.

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 PPUs, RPUs and related DERs will (i) be replaced with equivalent units of the new enterprise if there is no change in the recipient s job status for twelve months or (ii) fully vest if the recipient is severed or if the recipient s job is lower in status within twelve months of the change in control.

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In the event an award recipient s employment is terminated after the first anniversary of the grant date 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 s (i) performance units will contingently vest on a pro-rata basis for time worked over the Performance Period and final performance, measured at the end of the Performance Period, will determine the payout and (ii) time vested units will become fully vested and payable. 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:

Phantom IPO Units In conjunction with our initial public offering, in January 2006 our General Partner s board of directors granted phantom limited partnership units, or Phantom IPO Units, to key employees, including the executive officers. These Phantom IPO Units vested in January 2009 and were paid in common units. There was no performance condition associated with these Phantom IPO Units. Award recipients also received DERs based on the number of common units awarded, which were paid in cash on a quarterly basis from the date of the initial grant. These phantom IPO units 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.

Company Matching and Retirement Contributions to Defined Contribution Plans Employees may elect to participate in the DCP Midstream, LP 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. We match the first 6% of eligible compensation contributed by the employee to the plan. In addition, we make retirement contributions ranging from 4% to 7% of the eligible compensation of qualifying participants to the plan, based on years of service, up to the limits specified by the Internal Revenue Service. We have no defined benefit plans.

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 nonqualified, defined contribution 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, we make a contribution of up to 13% 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, 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 physical exam expenses. Finally, we provide all our employees with a monthly parking pass or a pass to be used on available public transportation systems.

We are a partnership and not a corporation for U.S. federal income tax purposes, and therefore, are not subject to the executive compensation tax deductible limitations of Internal Revenue Code § 162(m). Accordingly, none of the compensation paid to our named executive officers is subject to the limitation.

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 from

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the date the executive officer commences employment with us. Ownership is reported annually to the compensation committee. As of December 31, 2008, the unit ownership guidelines for the executive officers were as follows:

	Number of Units
CEO	28,000
CFO	10,000
Vice Presidents	10,000

Report of the Compensation Committee

The compensation committee has reviewed and discussed with management the Compensation Discussion and Analysis presented above. Members of management with whom the compensation committee had discussions are the Chief Executive Officer of the General Partner and the Group Vice President and Chief Administrative Officer of DCP Midstream, LLC. In addition, the compensation committee engaged the services of BDO Seidman, LLP, and a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for our executives. 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, 2008.

Compensation Committee

Alan N. Harris (Chairman)
Gregory J. Goff
Frank A. McPherson
Thomas C. O Connor

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 :

Name and Principal Position	Year	Salary	LTIP Awards(e)	Non-Equity Incentive Plan Compensation	Change in Nonqualified Deferred Compensation Earnings(f)	All Other Compensation(g)	Total
Mark A. Borer(a)	2008	$ 358,538	$ (34,138)	$ 80,671	$ 56,236	$ 126,851	$ 588,158
President and Chief	2007	$ 341,000	$ 151,763	$ 331,043	$ 36,518	$ 80,908	$ 941,232
Executive Officer	2006	$ 47,215	$	$ 46,655	$ 45	$ 2,052	$ 95,967
Angela A. Minas(b)	2008	$ 61,923	$ 3,541	$ 18,252	$	$ 49,199	$ 132,915
Vice President and Chief							
Financial Officer							

Thomas E. Long(c)	2008	$ 76,168	$ (396,593)	$	$ (61,564)	$ 31,955	$ (350,034)
Vice President and	2007	$ 199,212	$ 304,402	$ 145,605	$ 1,584	$ 54,268	$ 705,071
Chief Financial Officer	2006	$ 180,000	$ 92,191	$ 133,650	$	$ 33,182	$ 439,023
Michael S. Richards	2008	$ 181,748	$ (232,166)	$ 52,343	$ (6,765)	$ 65,136	$ 60,296
Vice President, General	2007	$ 172,615	$ 282,729	$ 125,903	$ 48	$ 46,431	$ 627,726
Counsel and Secretary	2006	$ 165,000	$ 88,390	$ 122,048	$	$ 32,717	$ 408,155
Greg K. Smith(d)	2008	$ 190,970	$ (236,289)	$ 32,226	$ (4,248)	$ 69,620	$ 52,279
Vice President, Business	2007	$ 179,644	$ 289,184	$ 131,080	$ 866	$ 51,185	$ 651,959
Development	2006	$ 170,000	$ 89,600	$ 121,444	$ 480	$ 36,044	$ 417,568

(a) Mr. Borer s employment with the General Partner commenced effective November 10, 2006.

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(b) Ms. Minas employment with the General Partner commenced effective September 8, 2008.

(c) Mr. Long s employment with the General Partner terminated effective April 30, 2008.

(d) Mr. Smith s employment with the General Partner terminated effective January 5, 2009, and he commenced employment with DCP Midstream, LLC. Mr. Smith has been replaced by Don Baldridge, formerly employed by DCP Midstream, LLC.

(e) The amounts in this column reflect the dollar amount recognized for financial statement reporting purposes in accordance with the provisions of Statement of Financial Accounting Standard No. 123(R), Share-Based Payment, or SFAS 123R, which incorporates re-measurement of awards for changes in the underlying assumptions used in prior periods, such as the unit price at the measurement date and the performance measure percentage. These amounts reflect our accounting expense and may not necessarily correspond to the actual value that will be realized by the named executives. The amounts exclude the impact of an estimated forfeiture rate under SFAS 123R, but do include the impact of forfeited awards if any of the named executives fail to perform the requisite service. Accordingly, the amounts may be negative due to these factors. This column reflects awards granted in January 2006 related to our initial public offering, and awards granted in conjunction with our LTIP. See Note 14 of the Notes to Consolidated Financial Statements in Item 8, Financial Statements and Supplementary Data.

(f) Amounts in this column are also included in the Nonqualified Deferred Compensation table below.

(g) 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.

Mark A. Borer, President and CEO

The annual base salary for Mr. Borer was $365,000 for 2008 and $341,000 for both 2007 and 2006, of which he deferred $125,488, $120,391 and $8,944 in 2008, 2007 and 2006, respectively. The LTIP awards are comprised of PPUs and RPUs pursuant to the LTIP. Under the 2008, 2007 and 2006 STI, Mr. Borer s target opportunity was 60% of his annual base salary, with the possibility of earning from 0 to 120% of his annual base salary in 2008, and 0% to 109% of his annual base salary in 2007 and 2006, depending on the level of performance in each of the STI objectives, which was pro rated in 2006 based upon his service period during 2006. While an employee at DCP Midstream, LLC during 2006, 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:

	2008	2007	2006
Company retirement contributions to defined contribution plans	$ 29,900	$ 29,950	$
Nonqualified deferred compensation program contributions	$ 50,160	$ 32,063	$ 1,945
DERs	$ 44,947	$ 18,370	$
Life insurance premiums(a)	$ 1,844	$ 1,225	$ 107

(a) Paid by the Partnership on behalf of Mr. Borer.

Angela A. Minas, Vice President and CFO

The annual base salary for Ms. Minas was $230,000 for 2008, of which she deferred $0 in 2008. The LTIP awards are comprised of PPUs and RPUs pursuant to the LTIP. Under the 2008 STI, Ms. Minas target opportunity was 45% of her annual base salary, with the possibility of earning from 0% to 90% of her annual base salary, depending on the level of performance in each of the STI objectives, which was pro rated in 2008 based upon her service period in 2008.

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All Other Compensation includes the following:

	2008
Relocation expenses	$ 41,901
Company retirement contributions to defined contribution plans	$ 5,131
DERs	$ 2,034
Life insurance premiums(a)	$ 133

(a) Paid by the Partnership on behalf of Ms. Minas.

Thomas E. Long, former Vice President and CFO

The annual base salary for Mr. Long was $215,000, $199,980 and $180,000 for 2008, 2007 and 2006, respectively, of which he deferred $131,070, $89,645 and $0 in 2008, 2007 and 2006, respectively. The LTIP awards are comprised of Phantom IPO Units, PPUs and RPUs pursuant to the LTIP. Under the 2008, 2007 and 2006 STI, Mr. Long s target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 90% of his annual base salary in 2008, and 0% to 82% of his annual base salary in 2007 and 2006, depending on the level of performance in each of the STI objectives.

All Other Compensation includes the following:

	2008	2007	2006
Company retirement contributions to defined contribution plans	$ 11,795	$ 28,476	$ 21,553
Nonqualified deferred compensation program contributions	$ 14,796	$	$
DERs	$ 5,324	$ 25,075	$ 10,981
Life insurance premiums(a)	$ 40	$ 717	$ 648

(a) 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 $185,000, $172,920 and $165,000 for 2008, 2007 and 2006, respectively, of which he deferred $15,397, $3,452 and $0 in 2008, 2007 and 2006, respectively. The LTIP awards are comprised of Phantom IPO Units, PPUs and RPUs pursuant to the LTIP. Under both the 2008 and 2007 STI, Mr. Richards target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 90% of his annual base salary in 2008, and 0% to 82% of his annual base salary in 2007 and 2006, depending on the level of performance in each of the STI objectives.

All Other Compensation includes the following:

	2008	2007	2006

Company retirement contributions to defined contribution plans	$ 23,000	$ 22,500	$ 20,891
Nonqualified deferred compensation program contributions	$ 6,550	$	$
DERs	$ 35,020	$ 23,309	$ 10,482
Life insurance premiums(a)	$ 566	$ 622	$ 594
Deminimus bonus	$	$	$ 750

(a) Paid by the Partnership on behalf of Mr. Richards.

Greg K. Smith, former Vice President, Business Development

The annual base salary for Mr. Smith was $195,000, $180,030 and $170,000 for 2008, 2007 and 2006, respectively, of which he deferred $7,638, $7,186 and $6,800 in 2008, 2007 and 2006, respectively. The LTIP awards are comprised of Phantom IPO Units, PPUs and RPUs pursuant to the LTIP. Under the 2008, 2007 and 2006 STI, Mr. Smith s target opportunity was 45% of his annual base salary, with the possibility of earning

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from 0% to 90% of his annual base salary in 2008, and 0% to 82% of his annual base salary in 2007 and 2006, depending on the level of performance in each of the STI objectives.

All Other Compensation includes the following:

	2008	2007	2006
Company retirement contributions to defined contribution plans	$ 23,926	$ 23,855	$ 21,928
Nonqualified deferred compensation program contributions	$ 9,265	$ 2,864	$ 2,864
DERs	$ 36,030	$ 23,818	$ 10,640
Life insurance premiums(a)	$ 399	$ 648	$ 612

(a) Paid by the Partnership on behalf of Mr. Smith.

Grants of Plan-Based Awards

Following are the grants of plan-based awards during the year ended December 31, 2008 for the General Partner s executive officers:

		Estimated Future Payouts under Non-Equity Incentive Plan Awards (a)			Estimated Future Payouts under Equity Incentive Plan Awards			Grant Date Fair Value of LTIP Awards
Name	**Grant Date**	**Minimum ($)**	**Target ($)**	**Maximum ($)**	**Minimum (#)**	**Target (#)**	**Maximum (#)**	**($)**
Mark A. Borer	NA	$ 109,500	$ 219,000	$ 438,000				$
PPUs	2/25/2008(b)	$	$	$	3,305	6,610	9,915	$ 237,167
RPUs	2/25/2008(c)	$	$	$	6,610	6,610	6,610	$ 237,167
Angela A. Minas	NA	$ 51,750	$ 103,500	$ 207,000				$
PPUs	2/25/2008(b)	$	$	$	848	1,695	2,543	$ 28,273
RPUs	2/25/2008(c)	$	$	$	1,695	1,695	1,695	$ 28,273
Michael S. Richards	NA	$ 41,625	$ 83,250	$ 166,500				$
PPUs	2/25/2008(b)	$	$	$	1,030	2,060	3,090	$ 73,913
RPUs	2/25/2008(c)	$	$	$	2,060	2,060	2,060	$ 73,913
Greg K. Smith	NA	$ 43,875	$ 87,750	$ 175,500				$
PPUs	2/25/2008(b)	$	$	$	1,088	2,175	3,263	$ 78,039
RPUs	2/25/2008(c)	$	$	$	2,175	2,175	2,175	$ 78,039

(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 represents units awarded under the LTIP. If minimum levels of performance are not met, then the payout may be zero.

(c) The number of units shown represents units awarded under the LTIP and these units vest at the end of the Vesting Period provided the individual is still employed by the Partnership.

The PPUs awarded on February 25, 2008 will vest in their entirety on December 31, 2010 if the specified performance conditions are satisfied and the RPUs awarded on February 25, 2008 will vest in their entirety on December 31, 2010 if the executive is still employed by the Partnership.

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Outstanding Equity Awards at Fiscal Year-End

Following are the outstanding equity awards for the General Partner s executive officers as of December 31, 2008:

	Outstanding LTIP 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)
Mark A. Borer		$	25,110	$ 238,269
Angela A. Minas		$	3,390	$ 31,866
Michael S. Richards	4,000	$ 37,600	12,730	$ 138,968
Greg K. Smith	4,000	$ 37,600	13,250	$ 144,416

(a) Phantom IPO Units awarded 1/3/2006; units vest in their entirety on 1/3/2009. For additional information, see Compensation Discussion and Analysis Other Compensation Phantom IPO Units.

(b) Value calculated based on the closing price of our common units at December 31, 2008.

(c) PPUs and RPUs awarded 5/5/2006, 2/26/2007 and 2/25/2008; units vest in their entirety over a range of 0% to 150% on 12/31/2008, 12/31/2009 and 12/31/2010, respectively, if the specified performance conditions are satisfied, except that the RPUs vest in their entirety on 12/31/2010; to determine the market value, the calculation of the number of units that are expected to vest for units granted in 2008 is based on assumed performance at 100%, for units granted in 2007 is based on assumed performance at 102%, and for units granted in 2006 is based on actual performance at 140.4%.

Options Exercises and Stock Vested

There were no options exercised and no limited partnership units held by our executive officers that vested during the year ended December 31, 2008.

Nonqualified Deferred Compensation

Following is the nonqualified deferred compensation for the General Partner s executive officers for the year ended December 31, 2008:

	Executive	Registrant	Aggregate

Name		Contributions in Last Fiscal Year(a)		Contributions in Last Fiscal Year(b)		Aggregate Earnings (Losses) in Last Fiscal Year(c)		Aggregate Withdrawals/ Distributions		Balance at December 31, 2008
Mark A. Borer	$	125,488	$	50,160	$	56,236	$		$	901,245
Thomas E. Long	$	131,070	$	14,796	$	(61,564)	$	(27,339)	$	148,337
Angela A. Minas	$		$		$		$		$	
Michael S. Richards	$	15,397	$	6,550	$	(6,765)	$		$	18,708
Greg K. Smith	$	7,638	$	9,265	$	(4,248)	$		$	44,305

(a) These amounts were included in the gross salary reported in the Salary column of the Summary Compensation table.

(b) These amounts are included in the Summary Compensation table within All Other Compensation.

(c) These amounts are included in the Summary Compensation table as Change in Nonqualified Deferred Compensation Earnings.

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 Effective February 17, 2009, 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 $40,000 retainer; (2) a board meeting fee of $1,250 for each board meeting attended; (3) a telephonic board meeting fee of $500 for each telephonic meeting attended; and (4) an annual grant of Phantom Units that approximate $40,000 of value, awarded pursuant to the LTIP, that have a six month vesting period. The directors also receive DERs, based on the number of units awarded, which are paid in cash on a quarterly basis. The Phantom Units will be paid in units upon vesting.

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 $1,250 for each special committee meeting attended. Finally, the Non-Employee Director members of the compensation committee will receive $1,250 for each compensation committee meeting attended.

Following is the compensation of the General Partner s Non-Employee Directors for the year ended December 31, 2008:

Name	Fees Earned	LTIP Awards(a)	DERs	Total
Paul F. Ferguson, Jr.	$ 90,000	$ 5,479	$ 2,762	$ 98,241
Frank A. McPherson	$ 72,500	$ 5,479	$ 2,762	$ 80,741
Thomas C. Morris	$ 69,000	$ 5,479	$ 2,762	$ 77,241
Stephen R. Springer	$ 89,500	$ 24,774	$ 1,475	$ 115,749

(a) The amounts in this column reflect the dollar amount recognized for financial statement reporting purposes, in accordance with the provisions of SFAS 123R, and include amounts from awards granted in conjunction with our LTIP. See Note 14 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

Mr. Ferguson is the audit committee chair and a member of the special committee.

Mr. McPherson was the special committee chair until February 2008, and is a member of the audit committee and the compensation committee.

Mr. Morris is a member of the audit committee and the special committee.

Mr. Springer is the special committee chair, and is a member of the audit committee.

The total aggregate grant date fair value of LTIP awards for the Non-Employee Directors for 2008 was $143,520. At December 31, 2008, Messrs. Ferguson, McPherson and Morris each had 666 Phantom IPO Units outstanding, which vested on January 3, 2009 and were paid in common units.

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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 February 23, 2009;

all of the directors of DCP Midstream GP, LLC;

each Named Executive Officer of DCP Midstream GP, LLC; and

all directors and executive officers of DCP Midstream GP, LLC as a group.

Percentage of total common units beneficially owned is based on 28,233,183 common units outstanding.

Name of Beneficial Owner(a)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
DCP LP Holdings, LP(b)(1)	8,246,451	29.2%
Kayne Anderson Capital Advisors, L.P.(c)	1,778,335	6.3%
Barclays PLC(d)	1,666,334	5.9%
Mark A. Borer	38,001	*
Angela A. Minas	15,000	*
Michael S. Richards	12,101	*
Don Baldridge	6,101	*
Alan N. Harris	9,842	*
Paul F. Ferguson, Jr.	6,334	*
John E. Lowe	40,001	*
Frank A. McPherson	15,666	*
Thomas C. Morris	20,667	*
Thomas C. O Connor	8,000	*
Stephen R. Springer	1,500	*
All directors and executive officers as a group (11 persons)	173,213	*

* 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 LP Holdings, LP and DCP Midstream, LLC is 370 17th Street, Suite 2500, Denver, Colorado 80202.

(c) As set forth in a Schedule 13G filed on February 17, 2009. The address of Kayne Anderson Capital Advisors, L.P. is 1800 Avenue of the Stars, Second Floor, Los Angeles, CA 90067.

(d) As set forth in a Schedule 13G filed on September 22, 2008. The address of Barclays PLC is 1 Churchill Place, London, E14 5HP, England.

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Equity Compensation Plan Information

The following table summarizes information about our equity compensation plan as of December 31, 2008.

	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			769,592
Total		$	769,592