DCP Midstream Partners, LP
Form 10-K
February 27, 2013
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended: December 31, 2012

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 001-32678

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**03-0567133**
(State or other jurisdiction	*(I.R.S. Employer*
of incorporation or organization)	*Identification No.)*
370 17th Street, Suite 2500	
Denver, Colorado	**80202**
(Address of principal executive offices)	*(Zip Code)*

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

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

Title of Each Class:	Name of Each Exchange on Which Registered:
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934, or the Act. Yes ¨ No x

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 x No ¨

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

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. ¨

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 definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Act. (Check one):

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2012, was approximately $1,618,328,000. 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, 2012.

As of February 22, 2013, there were outstanding 61,346,058 common units.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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DCP MIDSTREAM PARTNERS, LP

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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
Bcf	one billion cubic feet
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
MMBbls	one million 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
NGLs	natural gas liquids
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, plan, forecast and other similar words.

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

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

- the extent of changes in commodity prices and the demand for our products and services, our ability to effectively limit a portion of the adverse impact of potential changes in prices through derivative financial instruments over an extended period, and the potential impact of price and producers access to capital 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, the level and quality of gas production volumes around our assets and our ability to connect supplies to our gathering and processing systems in light of competition;

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

- our ability to access the debt and equity markets and the resulting cost of capital, which will depend on general market conditions, our financial and operating results, inflation rates, 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, our ability to comply with the covenants in our loan agreements and our debt securities, as well as our ability to maintain our credit ratings;

- the demand for NGL products by the petrochemical, refining or other industries;

- our ability to purchase propane from our suppliers and make associated profitable sales transactions for our wholesale propane logistics business;

- our ability to construct facilities on budget and in a timely fashion, which is partially dependent on obtaining required construction, 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 materials;

- the creditworthiness of counterparties to our transactions;

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

new, additions to and changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment, including climate change legislation and hydraulic fracturing regulations, or the increased regulation of our industry, and their impact on producers and customers served by our systems;

our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;

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- the amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs;

- industry changes, including the impact of consolidations, 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, including changes resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act.

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. The forward-looking statements in this report speak as of the filing date of this report. 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, 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 are currently engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs and condensate; and transporting, storing and selling propane in wholesale markets. Supported by our relationship with DCP Midstream, LLC and its owners, Spectra Energy Corp, or Spectra Energy, and Phillips 66, we have a management team dedicated to executing our growth strategy by acquiring and constructing additional assets. Prior to May 2012, DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, were owned 50% by Spectra Energy and 50% by ConocoPhillips. In May 2012, ConocoPhillips separated its business into two stand-alone publicly traded companies. As a result of this transaction, DCP Midstream, LLC is no longer owned 50% by ConocoPhillips. ConocoPhillips 50% ownership interest in DCP Midstream, LLC has been transferred to the new downstream company, Phillips 66.

Our operations are organized into three business segments: Natural Gas Services, NGL Logistics and Wholesale Propane Logistics. A map representing the geographic location and type of our assets for all segments is set forth below. Additional maps detailing the individual assets can be found on our website at *www.dcppartners.com*. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this report. For more information on our segments, see the *Our Operating Segments* discussion below.

OVERVIEW AND STRATEGIES

Our Business Strategies

Our primary business objectives are to have sustained company profitability, a strong balance sheet and profitable growth thereby increasing our cash distribution per unit over time. We intend to accomplish these objectives by executing the following business strategies:

Dropdown: maximize opportunities provided by our partnership with DCP Midstream, LLC. We plan to execute our growth in part through pursuing accretive dropdown opportunities from DCP Midstream, LLC. We believe there will continue to be significant opportunities as DCP Midstream, LLC continues to build its infrastructure. Given the significant level of growth opportunities currently in DCP Midstream,

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LLC s footprint, we would expect relatively more emphasis on dropdown activities over the next few years. However, we cannot say with any certainty that these opportunities will be made available to us, or that we will choose to pursue any such opportunity.

Acquire: pursue strategic and accretive third party acquisitions. We pursue strategic and accretive third party 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.

Build: capitalize on organic expansion opportunities. We continually evaluate economically attractive organic expansion opportunities to construct 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 or to build new processing capacity. We also believe there are opportunities to continue to expand our NGL Logistics and Wholesale Propane Logistics businesses.

Our Competitive Strengths

We believe that we are well positioned to execute our business strategies and achieve one of our primary business objectives of increasing our cash distribution per unit because of the following competitive strengths:

Affiliation with DCP Midstream, LLC and its owners. Our relationship with DCP Midstream, LLC and its owners, Spectra Energy and Phillips 66, 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), and the largest producer and marketer of NGLs in the United States. 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 most 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.

We believe we are an important growth vehicle and a key source of funding for DCP Midstream, LLC to pursue the acquisition, expansion and organic construction of midstream natural gas, NGL, wholesale propane and other complementary midstream energy businesses and assets. DCP Midstream, LLC has also provided us with growth opportunities through acquisitions directly from it and joint ventures with it. We believe we will have future opportunities to make additional acquisitions with or directly from DCP Midstream, LLC as well as form joint ventures with it; however, we cannot say with any certainty which, if any, of these opportunities 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 owners, we believe we have strong commercial relationships throughout the energy industry and access to DCP Midstream, LLC s broad operational, commercial, technical, risk management and administrative infrastructure.

DCP Midstream, LLC has a significant interest in us through its approximately 1% general partner interest in us, its ownership of our incentive distribution rights and an approximately 27% limited partner interest in us. We were party to an omnibus agreement, or the Omnibus Agreement, with DCP Midstream, LLC and some of its affiliates that governed our relationship among them regarding the operation of most of our assets, as well as certain reimbursements and other matters. On February 14, 2013, we entered into a Services Agreement with DCP Midstream, LLC, which replaces the Omnibus Agreement, whereby DCP Midstream, LLC will continue to provide us with the general and administrative services previously provided under the Omnibus Agreement. The annual amounts payable in future years to DCP Midstream, LLC under the Services Agreement will be consistent with the fee structure previously payable under the Omnibus Agreement. Pursuant to the Services Agreement, we will reimburse DCP Midstream, LLC for expenses and expenditures incurred or payments made on our behalf.

Strategically located assets. Each of our business segments has assets that are strategically located in areas with the potential for increasing 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 Texas, Michigan, Colorado, Louisiana, the Gulf of Mexico, Oklahoma, and Wyoming. These natural gas gathering systems provide a variety of services to our customers including natural gas gathering, compression, treating, processing, fractionation, storage and transportation services. The strategic location of our assets, coupled with their geographic diversity, presents us with continuing opportunities to provide competitive natural gas services to our customers and attract new natural gas production. Our NGL Logistics segment has strategically located NGL transportation pipelines in Texas, Colorado, Kansas, and Louisiana, which are major NGL producing regions, and an NGL storage facility in Michigan. Our NGL pipelines connect to various natural gas processing plants and transport the NGLs to large fractionation facilities, a petrochemical plant or a third party underground NGL storage facility along the Gulf Coast. Our NGL storage facility in Michigan is strategically adjacent to the Sarnia, Canada refinery and petrochemical corridor. Our Wholesale Propane Logistics Segment has terminals in the mid-Atlantic, northeastern and upper midwestern states that are strategically located to receive and deliver propane to some 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 commodity hedging program, generate relatively stable cash flows. While certain of our gathering and processing contracts subject us to commodity price risk, we have mitigated a 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 2016 with fixed price commodity swaps and collar arrangements.

Integrated package of midstream services. We provide an integrated package of services to natural gas producers, including gathering, compressing, treating, processing, transporting, storing and selling natural gas, as well as producing, fractionating, transporting, storing and selling NGLs and condensate. 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 logistics capabilities along with our propane storage assets and services allow 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 include some of the most senior officers and former senior officers of DCP Midstream, LLC and other energy companies who have extensive experience in the midstream industry. We believe our management team has a proven track record of enhancing value through the acquisition, optimization and integration of midstream assets.

Midstream Natural Gas Industry Overview (Natural Gas Services and NGL Logistics)

General

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, compressing, treating, processing, transporting, storing and selling of natural gas, and producing, fractionating, transporting, storing and selling NGLs.

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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 deplete, it becomes increasingly difficult to deliver the remaining lower pressure production from the well against the prevailing gathering system pressures. 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

The principal component of natural gas is methane, but most natural gas produced at the wellhead 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 residue natural gas 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 at the wellhead 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.

In addition to NGLs, natural gas collected at the wellhead through a gathering system may also contain impurities, such as water, sulfur compounds, nitrogen or helium, which must also be removed to meet the

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quality standards for long-haul pipeline transportation. As a result, gathering systems and natural gas processing plants will typically provide ancillary services prior to processing such as dehydration, treating to remove impurities and condensate separation. 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 liquefied hydrocarbons from the natural gas stream. Once the condensate has been removed, it may be stabilized for transportation away from the processing plant via truck, rail, or pipeline.

Natural Gas and NGL Transportation and Storage

After gas collected through a gathering system is processed to meet quality standards required for transportation and NGLs have been extracted from natural gas, the residue natural gas is shipped on long-haul pipelines or injected into storage facilities. The NGLs are typically transported via NGL pipelines or trucks to a fractionator for separation of the NGLs into their individual component parts. Natural gas and NGLs may be held in storage facilities to meet future seasonal and customer demands. Storage facilities can include marine, pipeline and rail terminals, and underground facilities consisting of salt caverns and aquifers used for storage of natural gas and various liquefied petroleum gas products including propane, mixed butane, and normal butane. Rail, truck and pipeline connections provide varying ways of transporting natural gas and NGLs to and from storage facilities.

Wholesale Propane Logistics Overview

General

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 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 United States or in foreign locations, particularly Canada, the North Sea, East Africa and the Middle East. There are limited but a growing number of processing plants, fractionation facilities and propane production in the northeastern United States.

Propane Demand

Propane demand is typically highest in suburban and rural areas where natural gas is not readily available, such as the northeastern United States. Propane is supplied by wholesalers to retailers to be sold to residential and commercial consumers primarily for heating and industrial applications. Propane demand is typically highest in the winter heating season months of October through April.

Transportation and Storage

Due to the region s limited, yet growing, propane production and relatively high demand, the mid-Atlantic and northeastern United States are importers of propane. These areas rely on pipeline, marine and rail sources for incoming supplies from both domestic and foreign locations. Independent terminal operators and wholesale distributors, own, lease or have access to propane storage facilities that receive supplies via pipeline, rail or ship. 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 pipeline, rail and marine 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. Typically independent retailers will rely on independent trucking companies to pick up propane at the propane wholesalers rack and transport it to the retailer at its location.

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OUR OPERATING SEGMENTS

Natural Gas Services Segment

General

Our Natural Gas Services segment consists of a geographically diverse complement of assets and ownership interests that provide a varied array of wellhead to market services for our producer customers. These services include gathering, compressing, treating, processing, transporting and storing natural gas. These assets are positioned in certain areas with active drilling programs and opportunities for both organic growth and readily integrated acquisitions. Our Natural Gas Services segment operates in seven states in the continental United States: Arkansas, Colorado, Louisiana, Michigan, Oklahoma, Texas and Wyoming. The assets in these states include our Southeast Texas system (of which 33.33% and 66.67% were acquired in January 2011 and March 2012, respectively), our East Texas system (of which the remaining 49.9% was acquired in January 2012, and the Crossroads system which was acquired in July 2012), our Michigan system, our 75% operating interest in our Colorado system (Collbran system), our Northern Louisiana system (including the Minden, Ada and Pelico systems), our 40% limited liability company interest in the Discovery system located off and onshore in Southern Louisiana, our Southern Oklahoma system (Lindsay system), our Wyoming system (Douglas system), and our 33.33% interest in the Eagle Ford system (which was acquired in November 2012). This geographic diversity helps to mitigate our natural gas supply risk in that we are not tied to one natural gas resource type or 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 11,400 miles of pipe, seventeen processing plants, five treating plants, two natural gas storage facilities and five NGL fractionation facilities. The seventeen processing plants that service our natural gas gathering systems include sixteen cryogenic facilities with approximately 1,865 MMcf/d of processing capacity and one refrigeration facility with approximately 45 MMcf/d of processing capacity. The natural gas storage facilities include 850 MMcf of leased storage on our Pelico system, and our Southeast Texas system s 8 Bcf salt dome storage facility. In addition to our existing assets, our wholly owned Eagle 200 MMcf/d natural gas processing plant is mechanically complete and is in the process of commencing operations. The Eagle Ford system is constructing a 200 MMcf/d cryogenic natural gas processing plant in the Eagle Ford shale, the Goliad plant, that we expect to be completed in the first quarter of 2014. We are constructing an additional storage cavern at Southeast Texas that we expect to be completed in the third quarter of 2013. Additionally, we, along with Williams Partners L.P., are constructing a 215-mile subsea gathering pipeline in the Gulf of Mexico, as part of our 40% interest in the Discovery system that we expect to be completed in mid-2014.

During 2012, the volume throughput on our assets was in excess of 1.6 Bcf/d, originating from a diversified mix of customers. Our 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. During 2012, the combined NGL production from our processing facilities was in excess of 65,000 Bbls/d and was delivered and sold into various NGL takeaway pipelines or transported by truck.

Our natural gas gathering systems have the ability to deliver gas into numerous 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 and Transmission Systems, Plants, Fractionators and Storage Facilities

Following is operating data for our systems:

	2012 Operating data						
System	**Approximate Gas Gathering and Transmission Systems (Miles)**	**Plants**	**Fractionators**	**Approximate Net Nameplate Plant Capacity (MMcf/d) (a)**	**Approximate Natural Gas Storage Capacity (Bcf)**	**Natural Gas Throughput (MMcf/d) (a)**	**NGL Production (Bbls/d) (a)**
Southeast Texas	675	3(b)		400	8	257	14,531
East Texas	900	6(b)	1	860		614	29,033
Michigan	440	4(c)		455		291	
Colorado	40	1(c)		84		55	1,662
Minden	725	1(b)		115		65	4,141
Ada	130	1(b)		45		25	121
Pelico	600				1(d)	93	
Discovery	300	1(b)(d)	1(d)	240		165	6,761
Southern Oklahoma	225					20	2,210
Wyoming	1,400					37	3,590
Eagle Ford	6,000	5(b)	3	250		45	3,561
Total	11,435	22	5	2,449	9	1,667	65,610

(a) Represents total capacity allocated to our proportionate ownership share or total volumes allocated to our proportionate ownership share for 2012 divided by 365 days. We have a 40% limited liability company interest in Discovery, 75% interest in our Colorado system, and 33.33% interest in our Eagle Ford system. Volumes for the Eagle Ford system include our share of throughput volumes and NGL production from the date of acquisition in November 2012.

(b) Represents NGL extraction plants.

(c) Represents treating plants.

(d) Represents a location operated by a third party.

In January 2011 and March 2012, we acquired 33.33% and 66.67%, respectively, of DCP Southeast Texas Holdings, GP, or Southeast Texas, from DCP Midstream, LLC. The Southeast Texas system is a fully integrated midstream business which includes 675 miles of natural gas pipelines, three natural gas processing plants in Liberty and Jefferson Counties with processing capacity of 400 MMcf/d and natural gas storage assets in Beaumont with 8 Bcf of existing storage capacity.

In January 2012, we acquired the remaining 49.9% of the limited liability company interests in East Texas from DCP Midstream, LLC. Our East Texas system includes the Crossroads processing plant and associated gathering system acquired in July 2012. Our East Texas system gathers, transports, compresses, treats and processes natural gas and NGLs. Our East Texas facility may also fractionate NGLs, which can be marketed at nearby petrochemical facilities. Our East Texas system, located near Carthage, Texas, includes 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 and acts as a key exchange point for the purchase and sale of residue gas in the eastern Texas region. Our East Texas system consists of approximately 900 miles of pipe, processing capacity of 860 MMcf/d and fractionation capacity of 11 MBbls/d.

Our Michigan system consists of four natural gas treating plants, an approximately 330-mile gas gathering system with throughput capacity of 455 MMcf/d; an approximately 55-mile residue gas pipeline, the Bay Area pipeline; and a 75% interest in Jackson Pipeline Company, a partnership owning an approximately 25-mile residue pipeline; and a 44% interest in the 30-mile Litchfield pipeline.

Our Colorado system is comprised of a 75% operating interest in Collbran Valley Gas Gathering, LLC, or Collbran, and consists of assets in the southern Piceance Basin that gather natural gas at high pressure from over 20,000 dedicated and producing acres in western Colorado. The remaining 25% interest in the joint venture is held by Occidental Petroleum Corporation who is the primary producer on the system. The Collbran system has capacity of over 200 MMcf/d and enables gas deliveries to the third-party Meeker Plant through a downstream connection with Enterprise Products Partners LP. As a result of our arrangement with Enterprise Products Partners LP, we have decommissioned the processing services at our natural gas processing plant at the Anderson Gulch site. However, this plant will continue to provide treating and compression services as needed.

Our Northern Louisiana system includes our Minden and Ada systems, which gather natural gas from producers and deliver it for processing to the processing plants. It also includes our Pelico system, which stores natural gas and transports it to markets. Through our Northern Louisiana system, we offer producers and customers wellhead-to-market services. Our 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 areas of the United States.

Our Minden processing plant is a cryogenic natural gas processing and treating plant located in Webster Parish, Louisiana. This area includes a low pressure gathering system that compresses and processes natural gas for our producing customers and delivers residue gas into our Pelico intrastate system. NGLs produced at the Minden processing plant are delivered to our Black Lake pipeline.

Our 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.

Our 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. 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 Pelico system leases 850 MMcf of gas storage capacity from a third party.

We have a 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, with the remaining 60% owned by Williams Partners, L.P. The Discovery system is operated by Williams Partners, L.P. and includes 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; a cryogenic natural gas processing plant in Larose, Louisiana; a fractionator in Paradis, Louisiana; and an NGL pipeline connecting the gas processing plant to the fractionator. The Discovery system 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. In January 2012, we, along with Williams Partners L.P., announced a planned expansion of the Discovery natural gas gathering pipeline system in the deepwater Gulf of Mexico. Discovery is constructing the Keathley Canyon Connector, a 20-inch diameter, 215-mile subsea natural gas gathering pipeline for production from the Keathley Canyon, Walker Ridge and Green Canyon areas in the central deepwater Gulf of Mexico. The Keathley Canyon Connector is expected to be completed in mid-2014.

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 mutual interest.

Our Southern Oklahoma system is located in the Golden Trend area of McClain, Garvin and Grady counties in southern Oklahoma. The system is adjacent to assets owned by DCP Midstream, LLC. Natural gas gathered by the system is delivered to DCP Midstream, LLC processing plants.

Our Wyoming system consists of over 1,400 miles of natural gas gathering pipelines that cover more than 4,000 square miles in the Powder River Basin in Wyoming. The system gathers primarily rich casing-head gas from oil wells at low pressure and delivers the gas to a third party for processing under a fee agreement.

In November 2012, we acquired 33.33% of the interest in DCP SC Texas GP, or the Eagle Ford system, from DCP Midstream, LLC. The Eagle Ford system is a fully integrated midstream business which includes 6,000 miles of gathering systems, production from 900,000 acres supported by acreage dedications or throughput commitments under long-term predominantly percent of proceeds agreements, five cryogenic natural gas processing plants totaling 760 MMcf/d of processing capacity, and three fractionation locations with total capacity of 36 MBbls/d.

DCP SC Texas GP is managed by a management committee with each partner having the right to designate up to three representatives to the management committee. The members of the management committee have voting power corresponding to their appointing partners respective ownership interests in DCP SC Texas GP. Most actions by DCP SC Texas GP require the affirmative vote of a majority of the ownership interests as represented by the management committee; however, certain significant actions require the unanimous affirmative vote of the management committee. DCP SC Texas GP 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 December 2012, DCP SC Texas GP announced plans to construct an additional cryogenic plant with 200 MMcf/d of processing capacity in Goliad County, Texas. Currently under construction, the Goliad plant will further expand the Eagle Ford system with an expected completion date in the first quarter of 2014. The plant, which will be constructed and funded by DCP SC Texas GP, is supported by long-term producer contracts and will serve growing demand from producers in the Eagle Ford shale.

Our wholly owned Eagle 200 MMcf/d natural gas processing plant, in Jackson County in the Eagle Ford area, is mechanically complete and is in the process of commencing operations.

Natural Gas and NGL Markets

The Southeast Texas system has numerous local natural gas market outlets and delivers residue gas into various interstate and intrastate pipelines, including the TETCO and Sabine pipelines. The Southeast Texas system makes NGL market deliveries directly to Exxon Mobil and to Mt. Belvieu via our Black Lake NGL pipeline.

The East Texas system delivers gas primarily through its Carthage Hub which delivers residue gas to multiple interstate and intrastate pipelines. 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 Mt. Belvieu for fractionation and sale.

The Michigan system delivers Antrim Shale gas to our four treating plants: the South Chester Treating Complex and the Warner plant, Turtle Lake and East Caledonia plants. Antrim Shale natural gas requires treating in order to meet downstream gas pipeline quality specifications. The treated gas is transported away 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.

The Colorado system gathers, compresses and delivers unprocessed gas to the third party Meeker plant.

The Northern Louisiana system has numerous market outlets for the natural gas that we gather on the system. Our Pelico natural gas pipeline connects to the Perryville Market Hub, a natural gas marketing hub in northeastern Louisiana. 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 Black Lake NGL pipeline through our Minden NGL pipeline. The Black Lake NGL pipeline delivers NGLs to Mt. Belvieu.

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 hubs.

The Southern Oklahoma system has access to a mix of mid-continent pipelines including OGT, Southern Star, and NGPL, and markets through DCP Midstream, LLC owned processing plants.

The Wyoming system delivers to a third party processing plant. Residue gas and NGLs are delivered to a third party pipeline, and also the Phillips 66-owned Powder River pipelines.

The Eagle Ford system has natural gas residue outlets including interstate and intrastate pipelines. The system delivers NGLs to the Gulf Coast petrochemical markets and to Mont Belvieu through the Sand Hills pipeline and other third party NGL pipelines. Our wholly owned Eagle plant will have delivery options into the Trunkline and Transco gas pipeline systems.

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.

Our contracts with our producing customers in our Natural Gas Services segment are primarily a mix of commodity sensitive percent-of-proceeds and percent-of-liquids contracts and non-commodity sensitive fee-based contracts. Our gross margin generated from percent-of-proceeds contracts is directly related to the price of natural gas, NGLs and condensate and our gross margin generated from percent-of-liquids contracts is directly related to the price of NGLs and condensate. Additionally, these contracts may include fee-based components. 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 and the Eagle Ford

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system are processed under percent-of-proceeds contracts. The contracts at our wholly owned Eagle plant are primarily fee-based. Our Wyoming system is a combination of percent-of-proceeds and fee-based contracts. Discovery has percent-of-liquids contracts and fee-based contracts, as well as some keep-whole contracts. Our Ada system is a combination of fee-based and keep-whole contracts. The producer contracts at our East Texas and Southeast Texas systems are primarily percent-of-liquids. The majority of the margin associated with contracts for our Pelico, Colorado and Michigan systems are fee-based.

Our Southeast Texas gas storage facility is primarily managed by us for our own account.

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 FERC for several types of service: traditional firm transportation service with reservation fees; 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.

In support of the construction of the wholly owned Eagle plant, we entered into a 15-year fee-based processing agreement with DCP Midstream, LLC, which also provides us with a fixed demand charge for a 150 MMcf/d of the 200 MMcf/d plant capacity along with a throughput fee on all volumes processed.

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, store 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 NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

NGL Logistics Segment

General

We operate our NGL Logistics business in the states of Michigan, Colorado, Kansas, Texas and Louisiana.

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Our NGL pipelines transport NGLs from natural gas processing plants to fractionation facilities, a petrochemical plant and a third party underground NGL storage facility. In aggregate, our NGL transportation business has 114 MBbls/d of capacity and, in 2012, had average throughput of approximately 77 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, and will likely experience periods in the future, when higher relative natural gas prices reduce the volume of NGLs produced at plants connected to our NGL pipelines.

Our NGL fractionation facilities in the Denver-Julesburg Basin, or DJ Basin, in Colorado and our partially owned facilities in Mont Belvieu, Texas, separate NGLs received from processing plants into their individual component parts. The fractionation facilities provide services on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of NGLs fractionated and the level of fees charged to customers.

Our NGL storage facility, located in Marysville, Michigan with strategic access to Canadian NGLs, has approximately 7 MMBbls of propane and butane storage. Our facility serves regional refining and petrochemical demand, and helps to balance the seasonality of propane distribution in the midwestern and northeastern United States and in Sarnia, Canada. We provide services to customers primarily on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product injected, stored and withdrawn, and the level of fees charged to customers.

NGL Pipelines

Following is operating data for our NGL pipelines:

		2012 Operating data	
System	**Approximate System Length (Miles)**	**Approximate Capacity (MBbls/d) (a)**	**Pipeline Throughput (MBbls/d) (b)**
Wattenberg	480	22	18
Seabreeze	56	41	31
Wilbreeze	39	11	11
Black Lake	317	40	17
Total	892	114	77

(a) Represents total capacity divided by 365 days.

(b) Represents total throughput for 2012 divided by 365 days.

Wattenberg Pipeline. The Wattenberg interstate NGL pipeline is approximately 480 miles long and has capacity of 22 MBbls/d. It originates in the DJ Basin in Colorado and terminates near the Conway hub in Bushton, Kansas. The pipeline is currently connected to DCP Midstream, LLC plants in the DJ Basin.

Seabreeze and Wilbreeze Pipelines. The Seabreeze intrastate NGL pipeline is located in Matagorda, Jackson and Calhoun Counties, Texas. Seabreeze is approximately 56 miles long and has capacity of 41 MBbls/d. In 2012, average throughput was approximately 31 MBbls/d. The Seabreeze pipeline receives NGLs from the Wilbreeze NGL pipeline, Williams Markham Plant, and Enterprise s Dean Pipeline. The Seabreeze pipeline delivers the NGLs it receives from these sources to a third-party fractionator, its associated third party storage facility, and Copano s Liberty Pipeline. The Wilbreeze intrastate NGL pipeline is located in Lavaca and Jackson Counties, Texas. Wilbreeze is approximately 39 miles long and has capacity of 11 Mbbls/d. In 2012, average throughput was approximately 11 MBbls/d. The Wilbreeze pipeline receives NGLs from the Wilcox plant and the Sand Hills pipeline, and delivers the NGLs it receives from these sources to the Seabreeze pipeline and Enterprise s Eagle pipeline.

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Black Lake Pipeline. The Black Lake interstate NGL pipeline originates in northwestern Louisiana and terminates in Mont Belvieu, Texas. The Black Lake pipeline is 317 miles long and has capacity of approximately 40 MBbls/d. In 2012, average throughput was approximately 17 MBbls/d. Black Lake receives NGLs from gas processing plants in northwestern Louisiana, including our Ada and Minden processing plants, XTO Energy Inc. s Cotton Valley processing plant, and Regency Intrastate Gas, LLC s Dubach processing plant. Black Lake also receives NGLs from gas processing plants in southeastern Texas and Eagle Rock s Brookland processing plant. The Black Lake pipeline is the sole NGL pipeline for these natural gas processing plants. Black Lake delivers the NGLs it receives from these sources to fractionation plants in Mont Belvieu, Texas including our partially owned Enterprise and Mont Belvieu 1 fractionators.

Black Lake is owned by us and has been operated by DCP Midstream, LLC since November 2010. Prior to July 27, 2010, we owned a 45% interest in Black Lake, while DCP Midstream, LLC owned a 5% interest. The remaining 50% was owned by an affiliate of BP PLC, who also operated the pipeline prior to November 2010. Prior to our acquisition of the remaining 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary.

Texas Express Pipeline. The Texas Express intrastate NGL pipeline, of which we own 10%, is under construction and will be approximately 580 miles. The Texas Express Pipeline will have an initial capacity of approximately 280 MBbls/d and has long-term, fee-based, ship-or-pay transportation commitments of 252 MBbls/d, including a commitment from DCP Midstream, LLC of 20 MBbls/d. Originating near Skellytown in Carson County, Texas, the 20-inch diameter pipeline will extend to Enterprise s natural gas liquids fractionation and storage complex at Mont Belvieu, Texas, and will provide access to other third party facilities in the area. The pipeline is expected to be completed in the second quarter of 2013 and begin operations in the third quarter of 2013.

NGL Fractionation Facilities

Our DJ Basin NGL fractionators in Colorado are located on DCP Midstream, LLC s processing plant sites and are operated by DCP Midstream, LLC, one of the largest gatherers and processors in the DJ Basin, who delivers NGLs to the fractionators under a long-term fractionation agreement.

Our NGL fractionation facilities in Mont Belvieu, Texas consist of the Enterprise fractionator operated by Enterprise Products Partners L.P., of which we acquired a 12.5% interest in July 2012, and the Mont Belvieu 1 fractionator operated by ONEOK Partners, of which we acquired a 20% interest in July 2012.

NGL Storage Facility

Our NGL storage facility is located on 620 acres of land in Marysville, Michigan and includes nine underground salt caverns with approximately 7 MMBbls of storage capacity and rail, truck and pipeline connections providing an important supply point for refiners, petrochemical plants and wholesale propane distributors in the Sarnia, midwestern and northeastern markets, including our Wholesale Propane business.

Customers and Contracts

Our Marysville NGL storage facility serves retail and wholesale propane customers, as well as refining and petrochemical customers, under one to three year term storage agreements. Our margins for this facility are primarily fee-based.

The Wattenberg pipeline is an open access pipeline with access to numerous gas processing facilities in the DJ Basin. Effective January 1, 2011, we entered into a 10-year dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC s processing facilities are dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenue under our tariff.

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

DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a long-term transportation agreement. The Seabreeze pipeline collects fee-based transportation revenue under this agreement.

DCP Midstream, LLC has historically been the largest active shipper on the Black Lake pipeline, accounting for approximately 37% of total throughput in 2012. The Black Lake pipeline generates revenues through a FERC-regulated tariff.

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DCP Midstream, LLC supplies certain committed NGLs to our DJ Basin NGL fractionators under fee-based agreements that are effective through March 2018.

Competition

The NGL logistics business is highly competitive in our markets and includes interstate and intrastate pipelines, integrated oil and gas companies that produce, fractionate, transport, store and sell NGLs, and underground storage facilities. Competition is often the greatest in geographic areas experiencing robust drilling by producers, strong petrochemical demand and during periods of high NGL prices relative to natural gas. Competition is also increased in those geographic areas where our contracts with our customers are shorter 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, Vermont and Virginia. Our operations serve the large propane markets in the northeastern, mid-Atlantic, and upper midwestern states.

Due to our multiple propane supply sources, annual and long-term propane supply purchase arrangements, storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our 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 result in our maintaining favorable relationships with our customers and allowing us to remain a supplier to many of the large distributors in the northeastern and mid-Atlantic United States. As a result, we serve as the baseload provider of propane supply to many of our propane distribution customers.

Pipeline deliveries to the northeastern and mid-Atlantic markets 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 excess capacity, which provides us with opportunities to increase our volumes with minimal additional cost.

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Our Terminals

Our operations include one owned propane marine terminal with storage capacity of 476 MBbls, one leased propane marine terminal with storage capacity of 424 MBbls, one propane pipeline terminal with storage capacity of 56 MBbls, six owned propane rail terminals with aggregate storage capacity of 21 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. Our leased marine terminal is on a lease agreement through April 2014. 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 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 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.

Propane Supply

Our wholesale propane business has a strategic network of supply arrangements under annual and multi-year agreements with index-based pricing. The remaining supply is purchased on month-to-month terms to match our anticipated sale requirements. Our primary suppliers of propane include a subsidiary of DCP Midstream, LLC, Aux Sable Liquid Products LP, Mark West and BP Canada. We may also obtain supply from our NGL storage facility in Marysville, Michigan. Our supply agreement with Spectra Energy expired April 30, 2012.

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.

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 periodically recognize non-cash lower of cost or market inventory adjustments, which occur when the market value of our commodities declines below our carrying value.

Customers and Contracts

We typically sell propane to 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 propane distributor desires to purchase propane from us on a fixed price basis, we may enter into fixed price sales agreements with terms of generally up to one year. We manage this commodity price risk by purchasing and storing propane, by entering into physical purchase agreements or by entering into offsetting 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 improved margins and a larger customer base. Historically, the majority 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 one third-party customer in our Wholesale Propane Logistics segment that accounted for greater than 10% of our segment revenues.

Competition

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

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Other

For additional information on our segments, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and Note 17 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

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

REGULATORY AND ENVIRONMENTAL MATTERS

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, of 1979, as amended, or HLPSA, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA 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 compliance in all material respects with these HLPSA 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. DOT, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), 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.

Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, (the Pipeline Safety and Job Creations Act) reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules proposed by DOT s PHMSA, address many areas of this legislation. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material cost to our operations.

The Pipeline Safety and Job Creation Act requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The new legislation gives PHMSA civil penalty authority up to $200,000 per day, with a maximum of $2.0 million for any related series of violations. Any material penalties or fines under these or other statues, rules, regulations or orders could have a material adverse impact on our business, financial condition, results of operation and cash flows.

We currently estimate we will incur costs of up to approximately $6.5 million between 2013 and 2017 to implement integrity management program testing along certain segments of our natural gas transmission and NGL pipelines, including our Wattenberg NGL pipeline acquired in January 2010. We believe that we are in compliance in all material respects with the NGPSA and the Pipeline Safety Improvement Act of 2002 and the Pipeline Safety and Job Creation Act.

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

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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 compliance in all material respects with all applicable laws and regulations relating to worker health and safety.

Propane Regulation

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

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, as amended, or NGA. Natural gas companies may not charge rates that have been determined to be unjust or unreasonable. In addition, FERC 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 investment cost. 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 gas 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 minimum rate or variable cost of performing service, provided they do not unduly discriminate.

Tariff changes can only be implemented upon approval by 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 FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If FERC determines, as required by the NGA, that a proposed change is just and reasonable, FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if FERC determines that a proposed change may not be just and reasonable as required by NGA, then 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 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, 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 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 FERC order requiring this change.

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 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, or EPACT 2005, and 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 FERC jurisdiction. In addition, EPACT 2005 gave FERC increased penalty authority for these violations. FERC may now issue civil penalties of up to $1.0 million

per day per violation, and possible criminal penalties of up to $1.0 million per violation and five years in prison. FERC may also order disgorgement of profits obtained in violation of FERC rules. FERC 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 subject to broad interpretation. In the past two years, FERC has relied on its EPACT 2005 enforcement authority in issuing a number of natural gas enforcement actions giving rise to the imposition of aggregate penalties of approximately $39.0 million and aggregate disgorgements of approximately $9.0 million. These orders reflect FERC s view that it has broad latitude in determining whether specific behavior violates the rules. Given FERC s broad mandate granted in EPACT 2005, if energy prices are high, or exhibit what FERC deems to be unusual trading patterns, 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

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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 FERC at least once every five years. The rate review may, but does not necessarily, involve an administrative-type hearing before 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 FERC authority to impose civil penalties for violations of the NGPA up to $1.0 million per day per violation and possible criminal penalties of up to $1.0 million per violation and five years in prison for violations occurring after August 8, 2005. The Pelico, Cipco and EasTrans systems are subject to FERC jurisdiction under Section 311 of the NGPA.

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 gathering facilities 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 continues to be a current issue in various FERC proceedings with respect to facilities that interconnect gathering and processing plants with nearby interstate pipelines, so the classification and regulation of our gathering facilities may be 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 where FERC has recognized a jurisdictional exemption for the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. 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.

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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 hedging 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. 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 FERC 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.

Interstate NGL Pipeline Regulation

The Black Lake and Wattenberg pipelines are interstate NGL pipelines subject to FERC regulation. FERC regulates interstate NGL pipelines under its Oil Pipeline Regulations, the Interstate Commerce Act of 1887, as amended, or ICA, and the Elkins Act of 1903, as amended. 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 and Wattenberg pipelines. 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 FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for pipelines regulated by FERC pursuant to the ICA. 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 2.65% 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. 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. FERC s indexing methodology is subject to review every five years; the current methodology remains in place through June 30, 2016.

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.

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

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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, compressing, fractionating or storing natural gas, 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;
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations; and
- regulating changes to 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.

Impact of Climate Change and Air Quality Standards

A number of states have adopted programs to reduce greenhouse gases, or GHG and depending on the particular program or jurisdiction, we could be required to purchase and surrender allowances, either for GHG emissions resulting from our operations (*e.g.*, compressor units) or from combustion of fuels (*e.g.*, oil or natural gas) we process. Also, the U.S. Environmental Protection Agency, or EPA, has declared that GHGs endanger public health and welfare, and is regulating GHG emissions from mobile sources such as cars and trucks

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According to the EPA, this final action on the GHG vehicle emission rule triggered regulation of carbon dioxide and other GHG emissions from stationary sources under various Clean Air Act programs at both the federal and state levels such as the Prevention of Significant Deterioration, or PSD, program and Title V permitting. These new requirements for stationary sources took effect on January 2, 2011. On June 26, 2012, the DC Circuit upheld, with no dissenting opinion, the EPA s GHG rules in their entirety. The EPA has also published more than a dozen rules relating to the mandatory reporting of GHG emissions, including mandatory reporting requirements of GHGs from petroleum and natural gas systems. The permitting and reporting program taken as a whole increase the costs and complexity of operating oil and gas operations in compliance with these legal requirements, with resulting potential to adversely affect our cost of doing business, demand for the oil and gas we transport and may require us 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.

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 the application of such requirements that could reasonably have a material impact on our operations or financial condition.

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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 also requires implementation of spill prevention, control and countermeasure plans, also referred to as SPCC plans, in connection with on-site storage of threshold quantities of oil. 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. 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 discharges. 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.

The Oil Pollution Act of 1990, as amended (OPA) addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities, including terminals, pipelines, and transfer facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages, and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in government penalties and civil liability.

Anti-Terrorism Measures

The federal Department of Homeland Security regulates the security of chemical and industrial facilities pursuant to regulations known as the Chemical Facility Anti-Terrorism Standards. These regulations apply to oil and gas facilities, among others, that are deemed to present high levels of security risk. Pursuant to these regulations, certain of our facilities are required to comply with certain regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

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, 2012, the General Partner or its affiliates employed 7 people directly and approximately 400 people who provided direct support for our operations through DCP Midstream, LLC.

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. We have also posted our code of business ethics on our website.

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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, condensate and NGLs, and propane;
- the success of our commodity and interest rate hedging programs in mitigating fluctuations in commodity prices and interest rates;
- the volume and quality of natural gas we gather, compress, treat, process, transport and sell, and the volume of NGLs we process, transport, sell, and store and the volume of propane we transport, sell, and store;
- the operational performance and efficiency of our assets, including our plants and equipment;
- the operational performance and efficiency of third-party processing, fractionation or other facilities that provide services to us;
- 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, NGLs 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 timing of our producers obligations to make volume deficiency payments to us;
- the amount of cash distributions we receive from our equity interests;
- the amount of cost reimbursements to our general partner;
- the amount of cash reserves established by our general partner; and
- new, additions to and changes in laws and regulations.

We have partial ownership interests in certain joint venture legal entities, including Discovery, the Eagle Ford system, CrossPoint, the Mont Belvieu fractionators and Texas Express, 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 our unitholders.

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 our 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, the demand for natural gas and crude oil, producers desire and ability to obtain necessary permits in an efficient manner, natural gas field characteristics and production performance, surface access and infrastructure issues, and our ability to compete for volumes from successful new wells. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells or because of 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, and our ability to make cash distributions.

Current economic conditions may adversely affect natural gas and NGL producers drilling activity and transportation spending levels, which may in turn negatively impact our volumes and results of operations and our ability to make distributions to our unitholders.

The level of drilling activity is dependent on economic and business factors beyond our control. Among the factors that impact drilling decisions are commodity prices, the liquids content of the natural gas production, drilling requirements for producers to hold leases, the cost of finding and producing natural gas and the general condition of the credit and financial markets. Natural gas prices have declined substantially compared to historical periods. For example, the twelve-month average New York Mercantile Exchange, or NYMEX, price of natural gas futures contracts per MMBtu was $3.54, $3.24 and $4.55 as of December 31, 2012, 2011 and 2010, respectively. The twelve-month average price per gallon for NGLs was $1.08, $1.39 and $1.10 as of December 31, 2012, 2011 and 2010, respectively, and the price of crude oil per barrel was $94.16, $95.12 and $79.53 as of December 31, 2012, 2011 and 2010, respectively. Commodity prices historically have been volatile and continue to be volatile. Crude oil prices have generally remained at favorable levels, while natural gas liquids prices have softened in relation to crude prices. Natural gas liquids and natural gas prices are currently below levels seen in recent years due to increasing supplies and higher inventory levels due to record warm weather last year. Natural gas drilling activity levels vary by geographic area, but in general, drilling remains firm in areas with liquids rich gas. Drilling remains weak in certain areas with dry gas where low commodity prices currently do not support the economics of drilling. However, advances in technology, such as horizontal drilling and hydraulic fracturing in shale plays, have led to certain geographic areas becoming increasingly accessible.

Furthermore, a sustained decline in commodity 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, and our NGL and natural gas storage assets, which could lead to reduced utilization of these assets. During periods of natural gas price decline and/or if the price of NGLs and crude oil declines, the level of drilling activity could decrease. When combined with a reduction of cash flow resulting from lower commodity prices, a reduction in our producers borrowing base under reserve-based credit facilities and lack of availability of debt or equity financing for our producers may result in a significant reduction in our producers spending for natural gas drilling activity, which could result in lower volumes being transported on our pipeline systems. Other factors that impact production decisions include 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 declines resulting from reductions in drilling activity, throughput on our pipelines and the utilization rates of our treating, processing and storage facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows and our ability to make cash distributions.

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 relates to fluctuations in crude oil prices. In the past, the prices of natural gas and crude oil have been 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 and may not always have a close relationship. 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 upstream or downstream operations;
- the level of domestic and offshore production;
- a general downturn in economic conditions, including demand for NGLs;
- the availability of 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/or 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 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 2016 with derivative instruments.

Our hedging 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 hedging activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. To mitigate a portion of our cash flow exposure to fluctuations in the price of NGLs, we have entered into derivative financial instruments relating to the future price of crude oil and NGLs. If the price relationship between NGLs and crude oil declines, our commodity price risk will 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 portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes from our gathering and processing operations through 2016 by entering into fixed price derivative financial instruments. 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 November 2016, 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 have mitigated a portion of our interest rate risk with interest rate swaps and forward-starting interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates and locking in rates on our anticipated future fixed-rate debt, respectively. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our Credit Agreement to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations. The forward-starting interest rate swap agreements lock in the interest rate associated with our anticipated future fixed-rate debt, thereby reducing the exposure to market rate fluctuations prior to issuance.

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 a portion of 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.

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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 hedging activities may not be as effective as we intend in reducing the volatility of our cash flows and, in certain circumstances, may actually increase the volatility of our earnings and cash flows. In addition, even though our management monitors our hedging activities, these activities can result in 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.

The amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport, sell and store, may be reduced if the pipelines and storage fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs.

The natural gas we gather, compress, treat, process, transport and store is delivered into pipelines for further delivery to end-users. If these pipelines are capacity constrained and cannot, or will not, accept delivery of the gas due to downstream constraints on the pipeline or changes in interstate pipeline gas quality specifications, we may be forced to limit or stop the flow of gas through our pipelines and processing and treating facilities. In addition, interruption of pipeline service upstream of our processing facilities would limit or stop flow through our processing and fractionation facilities. Likewise, if the pipelines into which we deliver NGLs are interrupted, we may be limited in, or prevented from conducting, our NGL transportation operations. Any number of factors beyond our control could cause such interruptions or constraints on pipeline service, including necessary and scheduled maintenance, or unexpected damage to the pipelines. Because our revenues and net operating margins depend upon (i) the volumes of natural gas we process, gather and transmit, (ii) the throughput of NGLs through our transportation, fractionation and storage facilities and (iii) the volume of natural gas we gather and transport, any reduction of volumes could adversely affect our operations and cash flows available for distribution to our unitholders.

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. We had no natural gas suppliers representing 10% or more of our total natural gas supply during the year ended December 31, 2012. 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 index-based pricing formulas. We identify primary suppliers as those individually

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representing 10% or more of our total propane supply. Our four primary suppliers of propane, two of which are affiliated entities, represented approximately 88% of our propane supplied during the year ended December 31, 2012. The propane supply agreement with Spectra Energy expired on April 30, 2012. In the event that we are unable to purchase propane from our significant suppliers due to their failure to perform under contractual obligations or otherwise, replace terminated or expired supply contracts, or if there are domestic or international supply disruptions, 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, our ability to satisfy customer demand, our revenue and results of operations would be adversely affected.

The adoption of financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

We hedge a portion of our commodity risk and our interest rate risk. The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including businesses like ours, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or Act, was signed into law by the President on July 21, 2010, and requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Act, the CFTC adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in Federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The CFTC has filed a notice of appeal with respect to this ruling. Under final rules adopted by the CFTC, we believe our hedging transactions will qualify for the non-financial, commercial end user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement. The Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

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

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

- participate in dropdown opportunities with DCP Midstream, LLC;
- 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 at reasonable rates.

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. 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. 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, if we did not properly value the acquired assets, or we did not identify significant liabilities associated with the acquired assets, the anticipated benefits from these acquisitions may not be fully realized.

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 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 and NGL storage facilities.

Third party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities may become unavailable to transport, process 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.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to

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lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services.

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 and at our owned marine terminal in Chesapeake, Virginia. 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.

Our operating results for our Wholesale Propane Logistics Segment fluctuate on a seasonal and quarterly basis.

Revenues from our Wholesale Propane Logistics Segment have seasonal characteristics. In many parts of the country, demand for propane and other fuels peaks during the winter months. As a result, our overall operating results fluctuate on a seasonal basis. Demand for propane and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our transportation arrangements relative to demand created by unusual weather patterns.

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.

Our assets and operations can be affected by weather and other weather related conditions.

Our assets and operations can be adversely affected by hurricanes, floods, tornadoes, wind, lightning, cold weather and other natural phenomena, which could impact our results of operations and make it more difficult for us to realize historic rates of return. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss and in some instances, we have been unable to obtain insurance on commercially reasonable terms, if at all. If we incur a significant disruption in our operations or a significant liability for which we were not fully insured, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

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.

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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 CIPCO pipeline system, 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 approved by 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 and Wattenberg pipeline system are interstate transporters of NGLs and are 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 $1.0 million per day for each violation and possible criminal penalties of up to $1.0 million per violation and five years in prison.

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

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 FERC fails to permit tariff rate increases requested by Discovery, or if 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, FERC also has the power to order refunds.

Under current policy, 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 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 $1.0 million per day for each violation and possible criminal penalties of up to $1.0 million per violation and five years in prison.

Recent spills and their aftermath could lead to additional governmental regulation of the offshore exploration and production industry, which may result in substantial cost increases or delays in our offshore natural gas gathering activities.

In April 2010, a deepwater exploration well located in the Gulf of Mexico, owned and operated by companies unrelated to us, sustained a blowout and subsequent explosion leading to the leaking of hydrocarbons. In response to this event, certain federal agencies and governmental officials ordered additional inspections of deepwater operations in the Gulf of Mexico. On May 28, 2010, a six-month federal moratorium was implemented on all offshore deepwater drilling projects. On October 12, 2010, the Department of the Interior announced it was lifting the deepwater drilling moratorium. Despite the fact that the drilling moratorium was lifted, this spill and its aftermath has led to additional governmental regulation of the offshore exploration and production industry and delays in the issuance of drilling permits, which may result in volume impacts, cost increases or delays in our offshore natural gas gathering activities, which could materially impact Discovery s operations, its Keathley Canyon construction, and our business, financial condition and results of operations. We cannot predict with any certainty what form any additional regulation or limitations would take.

Recently proposed or finalized rules imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

On April 16, 2012, the U.S. Environmental Protection Agency (EPA) approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from existing natural gas wells that are refractured and newly drilled and fractured wells through the use of reduced emission completions or green completions and completion combustion devices, such as flaring, as of January 1, 2015. In addition, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require modifications to the operations of our natural gas exploration and production customers as well as our operations including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our customers could result in reduced production by those customers and thus translate into reduced demand for our services which could in turn have an adverse effect on our business and cash available for distributions.

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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 in the future associated with proposed climate change legislation.

The United States Congress and some states where we have operations are considering legislation related to greenhouse gas emissions. In addition, there have recently been international conventions and efforts to establish standards for the reduction of greenhouse gases globally. The United States Congress may consider a legislation that would compel greenhouse gas emission reductions. Some of these proposals may include limitations, or caps, on the amount of greenhouse gas that can be emitted, as well as a system of emissions allowances. Legislation passed by the US House of Representatives in 2010, which was not taken up by the Senate, would have placed the entire burden of obtaining allowances for the carbon content of NGLs on the owners of NGLs at the point of fractionation. To the extent legislation is enacted that regulates greenhouse gas emissions, it could significantly increase our costs to (i) acquire allowances; (ii) operate and maintain our facilities; (iii) install new emission controls; and (iv) manage a greenhouse gas emissions program. If such legislation becomes law in the United States or any states in which we have operations and we are unable to pass these costs through as part of our services, it could have an adverse effect on our business and cash available for distributions.

Increased regulation of hydraulic fracturing could result in reductions, delays or increased costs in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas that we gather, process and transport.

Certain of our customers natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate production. While the underground injection of fluids is regulated by the U.S. EPA under the Safe Drinking Water Act (SDWA), fracturing is excluded from regulation unless the injection fluid is diesel fuel. Congress has recently considered legislation that would repeal the exclusion, allowing EPA to more generally regulate fracturing, and requiring disclosure of chemicals used in the fracturing process. If enacted, such legislation could require fracturing to meet permitting and financial responsibility, siting and technical specifications relating to well construction, plugging and abandonment. EPA is also considering various regulatory programs directed at hydraulic fracturing. For example, on October 20, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult for our customers to complete oil and natural gas wells in shale formations and increase their costs of compliance. In addition, the U.S. EPA is currently studying the potential adverse impact that each stage of hydraulic fracturing may have on the environment. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely.

In addition, federal agencies have recently initiated certain other regulatory initiatives or reviews of certain aspects of hydraulic fracturing that could further increase our natural gas exploration and production customer s costs and decrease their levels of production. On May 4, 2012, the federal Bureau of Land Management (BLM) announced draft rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon Native American Indian and other federal lands; a revised rule will undergo White House review and is anticipated to be released for public comment during the first quarter of 2013. Moreover, in late 2011, the EPA announced that it is developing standards for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and indicated that such standards would be proposed by 2014. The adoption and implementation of rules relating to hydraulic fracturing could result in increased expenditures for our natural gas exploration and production customers, which could cause them to reduce their production and thereby result in reduced demand for our services by these customers.

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.

Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, (the Pipeline Safety and Job Creations Act) reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules proposed by DOT s PHMSA, address many areas of this legislation. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material cost to our operations.

Although many of our natural gas facilities fall within a class that is not subject to current pipeline integrity requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with non-exempt pipelines. 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, or new requirements that may be imposed as a result of the Pipeline Safety and Job Creation Act, 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. With the exception of our Wattenberg pipeline, 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 up to approximately $6.5 million between 2013 and 2017 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, or new requirements that may be imposed as a result of the Pipeline Safety and Job Creation Act, which costs could be substantial.

We currently transport NGLs produced at our processing plants on our owned and third party NGL pipelines. Accordingly, in the event that an owned or third party NGL pipeline becomes inoperable due to any necessary repairs resulting from integrity testing program or for any other reason for any significant period of time, we would need to transport NGLs by other means. There can be no assurance that we will be able to enter into alternative transportation arrangements under comparable terms.

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 our financial results.

The construction of new midstream facilities or 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. Construction expenditures may occur over an extended period of time, yet we will not receive any material increases in cash flow until the project is completed and fully operational. Moreover, our cash flow from a project may be delayed or may not meet our expectations. 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 new systems or 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, these 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 new systems or additions to our existing gathering, transportation and propane terminal assets may require us to obtain new rights-of-way prior to constructing these 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 new systems or 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, NGLs, 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 systems 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.

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

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants and DCP Midstream, LLC. 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. Conversely, the amount of the purchase price less than DCP Midstream s basis in the net assets, if any, is recognized as an increase to partners equity.

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;
- 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, which may subject us to increased costs.

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, and the operations of third parties, are subject to many hazards inherent in the gathering, compressing, treating, processing, storing, transporting and fractionating of natural gas, propane and NGLs, including:

- damage to pipelines, plants, terminals, storage facilities and 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 from our pipelines, plants, terminals, or storage facilities, 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, including offshore wind. 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 such a policy.

Volatility in the capital markets may adversely impact our liquidity.

The capital markets may experience volatility, which may lead to 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. If 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 borrowings. A deterioration of the capital markets could adversely affect our ability to access funds on reasonable terms in a timely manner.

Future disruptions in the global credit markets may make equity and debt markets less accessible and capital markets more costly, create a shortage in the availability of credit and lead to credit market volatility, which could disrupt our financing plans and limit our ability to grow.

From time to time, public equity markets experience significant declines, and global credit markets experience a shortage in overall liquidity and a resulting disruption in the availability of credit. Future disruptions in the global financial marketplace, including the bankruptcy or restructuring of financial institutions, could make equity and debt markets inaccessible and adversely affect the availability of credit already arranged and the availability and cost of credit in the future. We have availability under our Credit Agreement, but our ability to borrow under that facility could be impaired if one or more of our lenders fails to honor its contractual obligation to lend to us.

As a publicly traded partnership, these developments could significantly impair our ability to make acquisitions or finance growth projects. We distribute all of our available cash, as defined in our partnership agreement, to our unitholders on a quarterly basis. We rely upon external financing sources, including the issuance of debt and equity securities and bank borrowings, to fund acquisitions or expansion capital expenditures or fund routine periodic working capital needs. Any limitations on our access to external capital, including limitations caused by illiquidity or volatility in the capital markets, may impair our ability to complete future acquisitions and construction projects on favorable terms, if at all. As a result, we may be at a competitive disadvantage as compared to businesses that reinvest all of their available cash to expand ongoing operations, particularly under adverse economic conditions.

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A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control.

A downgrade of our credit rating might increase our cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our ability to access capital markets could also be limited by a downgrade of our credit or the credit rating of our General Partner, DCP Midstream, LLC. Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold our securities, although such credit ratings may affect the market value of our debt instruments. Ratings are subject to revision or withdrawal at any time by the ratings agencies and no assurance can be given that we or DCP Midstream, LLC will maintain the current credit ratings.

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

We continue to have the ability to incur additional debt, subject to limitations within our Credit Agreement. 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 Credit Agreement 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 loan agreements may limit our ability to make distributions to unitholders and may limit our ability to capitalize on acquisitions and other business opportunities.

Our loan agreements contain covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our loan agreements contain covenants requiring us to maintain a certain leverage ratio and certain other tests. Any subsequent replacement of our loan agreements or any new indebtedness could have similar or greater restrictions. If our covenants are not met, whether as a result of reduced production levels of natural gas and NGLs as described above or otherwise, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

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

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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 or incur debt to make acquisitions, 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.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

The partnership is a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than equity in our subsidiaries and equity investees. As a result, our ability to make required payments on our notes depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit instruments, applicable state business organization laws and other laws and regulations. If our subsidiaries are prevented from distributing funds to us, we may be unable to pay all the principal and interest on the notes when due.

Our outstanding notes are senior unsecured obligations of our operating subsidiary, DCP Midstream Operating, LP, or DCP Operating, and are not guaranteed by any of our subsidiaries. As a result, our notes are effectively junior to DCP Operating s existing and future secured debt and to all debt and other liabilities of its subsidiaries.

Our 3.25% Senior Notes due 2015, 2.50% Senior Notes due 2017 and 4.95% Senior Notes due 2022, or our notes, are senior unsecured obligations of our indirect wholly-owned subsidiary, DCP Operating, and rank equally in right of payment with all of its other existing and future senior unsecured debt. All of our operating assets are owned by our subsidiaries, and none of these subsidiaries guarantee DCP Operating s obligations with respect to the notes. Creditors of DCP Operating s subsidiaries may have claims with respect to the assets of those subsidiaries that rank effectively senior to the notes. In the event of any distribution or payment of assets of such subsidiaries in any dissolution, winding up, liquidation, reorganization or bankruptcy proceeding, the claims of those creditors would be satisfied prior to making any such distribution or payment to DCP Operating in respect of its direct or indirect equity interests in such subsidiaries. Consequently, after satisfaction of the claims of such creditors, there may be little or no amounts left available to make payments in respect of our notes. As of December 31, 2012, DCP Operating s subsidiaries had no debt for borrowed money owing to any unaffiliated third parties. However, such subsidiaries are not prohibited under the indenture governing the notes from incurring indebtedness in the future.

In addition, because our notes and our guarantee of our notes are unsecured, holders of any secured indebtedness of us would have claims with respect to the assets constituting collateral for such indebtedness that are senior to the claims of the holders of our notes. Currently, we do not have any secured indebtedness. Although the indenture governing our notes places some limitations on our ability to create liens securing debt, there are significant exceptions to these limitations that will allow us to secure significant amounts of indebtedness without equally and ratably securing the notes. If we incur secured indebtedness and such indebtedness is either accelerated or becomes subject to a bankruptcy, liquidation or reorganization, our assets would be used to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on our notes. Consequently, any such secured indebtedness would effectively be senior to our notes and our guarantee of our notes, to the extent of the value of the collateral securing the secured indebtedness. In that event, noteholders may not be able to recover all the principal or interest due under our notes.

Our significant indebtedness and the restrictions in our debt agreements may adversely affect our future financial and operating flexibility.

As of December 31, 2012, our consolidated indebtedness was $1,625.0 million, which excludes $4.7 million in amortized discount. Our significant indebtedness and the additional debt we may incur in the future for potential acquisitions may adversely affect our liquidity and therefore our ability to make interest payments on our notes.

Debt service obligations and restrictive covenants in our Credit Agreement and the indenture governing our notes may adversely affect our ability to finance future operations, pursue acquisitions and fund other capital needs as well as our ability to make cash distributions unitholders. In addition, this leverage may make our results of operations more susceptible to adverse economic or operating conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

If we incur any additional indebtedness, including trade payables, that ranks equally with our notes, the holders of that debt will be entitled to share ratably with the holders of our notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding up of us or DCP Operating. This may have the effect of reducing the amount of proceeds paid to noteholders. If new debt is added to our current debt levels, the related risks that we now face could intensify.

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 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 and North Africa or other sustained military conflicts 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.

Recent acquisitions may not be beneficial to us.

Acquisitions involve numerous risks, including:

- the failure to realize expected profitability, growth or accretion;
- an increase in indebtedness and borrowing costs;
- potential environmental or regulatory compliance matters or liabilities;
- potential title issues;
- the incurrence of unanticipated liabilities and costs; and

the temporary diversion of management s attention from managing the remainder of our assets to the process of integrating the acquired businesses.

The assets recently acquired will also be subject to many of the same risks as our existing assets. If any of these risks or unanticipated liabilities or costs were to materialize, any desired benefits of these acquisitions may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

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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 owners. 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 Phillips 66, 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.

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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 and Services Agreements, as amended, between us, DCP Midstream, LLC and others will prohibit DCP Midstream, LLC and its affiliates, including Phillips 66, 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 Phillips 66, 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 Services 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.

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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 currently has the right 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 do not elect our general partner or its board of directors, and 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 are chosen by the members of our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

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 a significant percentage of our outstanding units. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. As of December 31, 2012, our general partner and its affiliates owned approximately 27% 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 assets include a 40% interest in the Discovery system, a 33.33% interest in the Eagle Ford system, a 10% interest in the Texas Express Pipeline, a 12.5% interest in the Mont Belvieu Enterprise Fractionator, a 20% interest in the Mont Belvieu 1 Fractionator, and a 50% interest in CrossPoint Pipeline, LLC, 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 SEC 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 any of our assets that are deemed to be investment securities.

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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 unitholders approval, which would dilute unitholders existing ownership interests.

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

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

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

If our general partner or its affiliates holding unregistered 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

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, or IRS, were to treat us as a corporation for federal income tax purposes, 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 a unitholder would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to him. Because a tax would be imposed upon us as a corporation, our cash available for distribution to a unitholder would be substantially reduced. Therefore, treatment of us as a corporation for federal tax purposes would result in a material reduction in the anticipated cash flow and after-tax return to a unitholder, likely causing a substantial reduction in the value of our common units.

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.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. For example, members of the U.S. Congress considered, and the President s Administration has proposed, substantive changes to the existing U.S. federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such change could negatively impact the value of an investment in our common units.

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 the State of Texas a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Imposition of such a tax on us by any other state will reduce the cash available for distribution to a 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.

Changes in tax laws could adversely affect our performance

We are subject to extensive tax laws and regulations, with respect to federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future.

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 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.

Unitholders may be required to pay taxes on income from us even if the unitholders do 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, unitholders 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. 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.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder s share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder s units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder s tax basis in its units.

In addition, the federal income tax liability of a unitholder could be increased if we dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to the our assets.

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

If unitholders sell 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 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 a unitholder sells its units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder receives 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, or 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 a unitholder is a tax-exempt entity or a non-U.S. person, the unitholder should consult its tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will 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 unitholders. 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. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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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 such 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.

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

We will be considered to have technically terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination, among other things, would 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 calendar year. Our termination could also 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 calendar year, 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. Under current law, a technical termination would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination 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. The IRS has announced a publicly traded partnership technical termination relief procedure, whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year, notwithstanding two partnership tax years resulting from the technical termination.

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, unitholders 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

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various jurisdictions in which we conduct business or own property, even if the unitholders do not live in any of those jurisdictions. Unitholders 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. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax or an entity level tax. It is each unitholder s responsibility to file all United States federal, foreign, state and local tax returns.

Some of the states in which we do business or own property may require us to, or we may elect to, withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding the amount of which may be greater or less than a particular unitholder s income tax liability to the state generally does not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

As of February 22, 2013, we own and operate processing plants and gathering systems located in Arkansas, Colorado, Louisiana, Michigan, Oklahoma, Texas and Wyoming, and an underground natural gas storage facility located in Texas, all within our Natural Gas Services segment; two owned and operated pipelines located in Texas, one owned and operated pipeline located in Texas and Louisiana, one owned and operated pipeline located in Colorado and Kansas, one owned and operated underground storage facility located in Michigan and two owned fractionation facilities located in Colorado within our NGL Logistics segment; and six owned propane rail terminals, five of which we operate, located in Maine, Massachusetts, New York, Pennsylvania and Vermont, one owned and operated marine terminal located in Virginia, and one owned and operated propane pipeline terminal located in Pennsylvania within our Wholesale Propane Logistics Segment. In addition within our Natural Gas Services segment, we own 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 a 33.33% interest in the Eagle Ford system, which owns processing plants, NGL fractionators and gathering systems in Texas, operated by DCP Midstream, LLC. Within our NGL Logistics segment, we own a 12.5% and 20% interest in the Enterprise and Mont Belvieu fractionators, respectively, which are operated by third parties. For additional details on these plants, storage facilities, propane terminals and pipeline systems, please read Business Natural Gas Services Segment, Business NGL Logistics Segment and Business Wholesale Propane 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 2500, 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 and commercial disputes 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. For more information, please read Business Regulation of Operations and Business Environmental Matters.

Prospect During the fourth quarter of 2011, we received a claim for arbitration (the Claim) filed with the American Arbitration Association by Prospect Street Energy, LLC and Prospect Street Ventures I, LLC (together, the Claimants) against EE Group, LLC (EE Group) and a number of other parties that previously owned, directly or indirectly, our Marysville NGL storage facility (collectively, the Respondents). EE Group is our indirect subsidiary which we acquired in connection with our acquisition of Marysville Hydrocarbons

Holdings, LLC (Marysville) on December 30, 2010 (the Acquisition). The Claim involves actions taken and time periods prior to our ownership of EE Group and Marysville, and includes several causes of action including claims of civil conspiracy, breach of fiduciary duty and fraud. We acquired a 90% interest in Marysville from Dart Energy Corporation, a 5% interest in Marysville from Prospect Street Energy, LLC and a 100% interest in EE Group, which owned the remaining 5% interest in Marysville. The Claimants seek, from the Respondents collectively, alleged actual, punitive and treble damages and disgorgement of profits, as well as fees and costs. The purchase agreements for the Acquisition contain indemnification and other provisions that may provide some protection to us for any breach of the representations, warranties and covenants made by the sellers in the Acquisition. In August 2012, we entered into a Settlement Agreement with the Claimants in which the Claimants have agreed that if an award is issued to the Claimants in the arbitration, the Claimants will not attempt to recover such an award from us. Notwithstanding that agreement, this matter is subject to the uncertainties inherent in any litigation, and the ultimate outcome of this matter may not be known for an extended period of time.

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.

Item 4. ***Mine Safety Disclosures***

Not applicable.

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PART II

Item 5. ***Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Common 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. The following table sets forth intra-day high and low sales prices of the common units, as reported by the NYSE, as well as the amount of cash distributions declared per quarter for 2012 and 2011.

Quarter Ended	High	Low	Distribution Per Common Unit
December 31, 2012	$ 47.05	$ 37.78	$ 0.6900
September 30, 2012	$ 46.50	$ 39.94	$ 0.6800
June 30, 2012	$ 46.36	$ 36.47	$ 0.6700
March 31, 2012	$ 49.93	$ 44.55	$ 0.6600
December 31, 2011	$ 47.92	$ 35.76	$ 0.6500
September 30, 2011	$ 42.92	$ 34.40	$ 0.6400
June 30, 2011	$ 44.80	$ 37.55	$ 0.6325
March 31, 2011	$ 42.58	$ 36.80	$ 0.6250

As of February 22, 2013, there were approximately 38 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. As of February 21, 2013, there were approximately 24,355 beneficial owners (held in street name) of our common units.

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.

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 $0.69 per unit, or $2.76 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. 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 As of December 31, 2012, the general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 1% and limited partner interest of 1%. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner s interest may be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest.

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 recent common unit offerings, 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 after the Subordination Period* section 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 28, 2013, we announced that the board of directors of DCP Midstream GP, LLC declared a quarterly distribution of $0.69 per unit, which was paid on February 14, 2013, to unitholders of record on February 7, 2013.

Equity Compensation Plans

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

Item 6. *Selected Financial Data*

The following table shows our selected financial data for the periods and as of the dates indicated, which is derived from the consolidated financial statements. These consolidated financial statements include our accounts, which have been combined with the historical assets, liabilities and operations of our additional 25.1% limited liability interest in East Texas, which we acquired from DCP Midstream, LLC in April 2009; our 100% interest in DCP Southeast Texas Holdings, GP, or Southeast Texas, of which 33.33% and 66.67% were acquired from DCP Midstream, LLC in January 2011 and March 2012, respectively; and commodity derivative hedge instruments related to the Southeast Texas storage business, which we acquired from DCP Midstream, LLC in March 2012. Prior to our acquisition of the remaining 66.67% interest in Southeast Texas, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method of accounting. Subsequent to our acquisition of the remaining 66.67% interest in Southeast Texas, we own 100% of Southeast Texas which we account for as a consolidated subsidiary. These transactions were between entities under common control and represented a change in reporting entity; accordingly, our financial information includes the historical results of entities and interests contributed to us by DCP Midstream, LLC 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.

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

	Year Ended December 31,				
	2012 (a)	2011 (a)	2010 (a)	2009 (a)	2008 (a)
	(Millions, except per unit amounts)				
Statements of Operations Data:					
Sales of natural gas, propane, NGLs and condensate	$ 1,465.9	$ 2,178.5	$ 1,975.1	$ 1,429.3	$ 2,791.1
Transportation, processing and other	185.0	172.2	130.3	104.9	96.9
Gains (losses) from commodity derivative activity, net (b)	69.8	7.7	3.0	(56.3)	84.6
Total operating revenues (c)	1,720.7	2,358.4	2,108.4	1,477.9	2,972.6
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	1,301.5	1,933.0	1,783.1	1,248.3	2,546.4
Operating and maintenance expense	123.2	125.7	98.3	84.2	95.0
Depreciation and amortization expense	63.4	100.6	88.1	76.9	65.0
General and administrative expense	45.8	48.3	45.8	43.1	43.9
Step acquisition equity interest re-measurement gain			(9.1)		
Other (income) expense	(0.5)	(0.5)	(2.0)	0.5	0.3
Other income affiliates			(3.0)		
Total operating costs and expenses	1,533.4	2,207.1	2,001.2	1,453.0	2,750.6
Operating income	187.3	151.3	107.2	24.9	222.0
Interest income				0.3	6.1
Interest expense	(42.2)	(33.9)	(29.1)	(28.3)	(32.8)
Earnings from unconsolidated affiliates (d)	28.9	22.7	23.8	18.5	18.2
Income before income taxes	174.0	140.1	101.9	15.4	213.5
Income tax expense	(1.0)	(0.5)	(1.5)	(1.0)	(1.3)
Net income	173.0	139.6	100.4	14.4	212.2
Net income attributable to noncontrolling interests	(5.0)	(18.8)	(9.2)	(8.3)	(36.1)
Net income attributable to partners	$ 168.0	$ 120.8	$ 91.2	$ 6.1	$ 176.1
Less:					
Net income attributable to predecessor operations (e)	(2.6)	(20.4)	(43.2)	(24.2)	(50.4)
General partner interest in net income	(41.2)	(25.2)	(16.9)	(12.7)	(13.0)
Net income (loss) allocable to limited partners	$ 124.2	$ 75.2	$ 31.1	$ (30.8)	$ 112.7
Net income (loss) per limited partner unit-basic	$ 2.28	$ 1.73	$ 0.86	$ (0.99)	$ 4.11
Net income (loss) per limited partner unit-diluted	$ 2.28	$ 1.72	$ 0.86	$ (0.99)	$ 4.11
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 1,727.4	$ 1,499.4	$ 1,378.6	$ 1,225.3	$ 1,106.1
Total assets	$ 2,972.0	$ 2,277.4	$ 2,147.2	$ 1,805.6	$ 1,745.1
Accounts payable	$ 146.3	$ 278.5	$ 211.0	$ 195.3	$ 154.5
Long-term debt	$ 1,620.3	$ 746.8	$ 647.8	$ 613.0	$ 656.5
Partners equity	$ 1,047.8	$ 885.9	$ 855.9	$ 590.0	$ 612.7
Noncontrolling interests	$ 35.4	$ 212.4	$ 220.1	$ 227.7	$ 167.7

Total equity	$ 1,083.2	$ 1,098.3	$ 1,076.0	$ 817.7	$ 780.4
Other Information:					
Cash distributions declared per unit	$ 2.700	$ 2.548	$ 2.438	$ 2.400	$ 2.390
Cash distributions paid per unit	$ 2.660	$ 2.515	$ 2.420	$ 2.400	$ 2.360

(a) Includes the effect of the following acquisitions prospectively from their respective dates of acquisition: (1) Michigan Pipeline & Processing, LLC acquired in October 2008; (2) certain companies acquired from

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MichCon Pipeline Company in November 2009; (3) the Wattenberg pipeline acquired from Buckeye Partners, L.P. in January 2010; (4) an additional 5% interest in Collbran Valley Gas Gathering LLC, acquired from Delta Petroleum Company in February 2010; (5) the Raywood processing plant and Liberty gathering system acquired in June 2010; (6) an additional 50% interest in Black Lake Pipeline Company, or Black Lake, acquired from an affiliate of BP PLC in July 2010; (7) Atlantic Energy acquired from UGI Corporation in July 2010; (8) Marysville Hydrocarbons Holdings, LLC acquired on December 30, 2010; (9) the DJ Basin NGL fractionators acquired in March 2011; (10) the remaining 49.9% interest in East Texas from DCP Midstream, LLC in January 2012; (11) a 10% ownership interest in the Texas Express Pipeline from Enterprise Products Partners, L.P. in April 2012; (12) a 12.5% interest in the Enterprise fractionator and a 20% interest in the Mont Belvieu 1 fractionator, from DCP Midstream, LLC in July 2012; (13) the Crossroads processing plant and 50% interest in CrossPoint Pipeline, LLC, acquired from Penn Virginia Resource Partners, L.P. in July 2012; and (14) a 33.33% interest in the Eagle Ford system from DCP Midstream, LLC in November 2012.

Prior to our acquisition of an additional 50% interest in Black Lake, in July 2010, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary.

(b) Includes the effect of the commodity derivative hedge instruments related to the Eagle Ford system, including the Goliad plant, acquired from DCP Midstream, LLC in November and December 2012, the Southeast Texas storage business acquired from DCP Midstream, LLC in March 2012 and the NGL Hedge acquired from DCP Midstream, LLC in April 2009.

(c) Prior to the acquisition of the remaining 49.9% limited liability company interest in East Texas in January 2012, we hedged the proportionate ownership of East Texas. Results shown include the unhedged portion of East Texas owned by DCP Midstream, LLC. Our consolidated results depict 75% of East Texas unhedged in all periods prior to the second quarter of 2009 and the remaining 49.9% of East Texas unhedged for all periods from the second quarter of 2009 through the fourth quarter of 2011.

(d) Includes our proportionate share of the earnings of our unconsolidated affiliates. Earnings include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the investments.

(e) Includes the net income attributable to an additional 25.1% limited liability company interest in East Texas prior to the date of our acquisition from DCP Midstream, LLC in April 2009; the initial 33.33% interest in Southeast Texas prior to the date of our acquisition from DCP Midstream, LLC in January 2011; and the remaining 66.67% interest in Southeast Texas and commodity derivative hedge instruments prior to the date of our acquisition from DCP Midstream, LLC in March 2012.

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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.

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

During 2012, we expanded our Natural Gas Services and NGL Logistics segments through approximately $1 billion in dropdowns from DCP Midstream, LLC, a third party acquisition, and organic expansion opportunities. We raised $455.2 million through the issuance of our common units, and $839.4 million through the issuance of 5 and 10-year Senior Notes, which were primarily used to finance our growth. In addition, we issued $228.7 million of common units to DCP Midstream as partial consideration for our drop downs.

2012 was a challenging year from a commodity price perspective, for example, the twelve-month average New York Mercantile Exchange, or NYMEX, price of natural gas futures contracts per MMBtu was $3.54, $3.24 and $4.55 as of December 31, 2012, 2011 and 2010, respectively. The twelve-month average price per gallon for NGLs was $1.08, $1.39 and $1.10 as of December 31, 2012, 2011 and 2010, respectively, and the price of crude oil per barrel was $94.16, $95.12 and $79.53 as of December 31, 2012, 2011 and 2010, respectively. Our significant fee-based business currently representing approximately 55% of our estimated margins, plus our highly hedged commodity position, mitigated a portion of our natural gas, NGL, and condensate commodity price risk. In 2013, we will continue executing our multi-faceted growth strategy, with an emphasis on dropdowns from DCP Midstream, LLC.

Our business is impacted by both commodity prices, which we partially mitigate through a multi-year hedging program, as well as volumes of throughput and sales of natural gas and NGLs. Various factors impact both commodity prices and volumes. Commodity prices historically have been volatile and continue to be volatile. Crude oil prices have generally remained at favorable levels, while NGL prices have softened in relation to crude prices. NGLs and natural gas prices are currently below levels seen in recent years due to increasing supplies and record warm weather. Although we have not experienced a significant impact to our natural gas throughput volumes as a result of decreased commodity prices, if commodity prices remain weak for a sustained period, our natural gas throughput volumes may be impacted, particularly if producers were to shut in gas. Natural gas drilling activity levels vary by geographic area, but in general, drilling remains firm in areas with liquids rich gas. Drilling remains weak in certain areas with dry gas where low commodity prices currently do not support the economics of drilling. However, advances in technology, such as horizontal drilling and hydraulic fracturing in shale plays, have led to certain geographic areas becoming increasingly accessible. Our long-term view is that commodity prices will be at levels that we believe will support sustained or increasing levels of domestic natural gas production. We use direct NGL hedges to mitigate a significant portion of our NGL price exposure, however, weakening of the relationship of natural gas liquids to crude oil prices does somewhat impact the effectiveness of our hedging program to mitigate our exposure to price fluctuations where we use crude oil to hedge our NGL price exposure.

NGL prices are also impacted by the demand from petro-chemical and refining industries. The petro-chemical industry is making significant investment in building or expanding facilities to convert chemical plants from heavier oil-based feed stock to lighter NGL-based feed stock, including ethane. This increased demand should support increasing ethane supplies. In addition, propane export facilities are also being expanded or built, which is expected to support increasing propane supply. Although there can be, and has been, near-term volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to support increasing supply.

The global economic outlook continues to be cause for concern for U.S. financial markets and businesses and investors alike. A further slowdown in global economic growth or a potential liquidity crisis may lead to further declines in commodity prices. This uncertainty may contribute to continuing volatility in financial and commodity markets.

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Increased activity levels in liquids rich gas basins are creating capacity constraint concerns. The amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport, sell and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs.

Increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low historical cost have enabled us to continue executing our multi-faceted growth strategy, with an emphasis on dropdowns from DCP Midstream, LLC. Our multi-faceted growth strategy may take numerous forms such as accretive dropdown opportunities from DCP Midstream, LLC, third-party acquisitions, joint venture opportunities and organic build opportunities within our footprint. Dropdowns from DCP Midstream, LLC in 2012 were approximately $1.0 billion.

Some of our recent growth projects include the following:

- On January 3, 2012, we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC for $165.0 million.

- On March 30, 2012, we acquired the remaining 66.67% interest in the Southeast Texas joint venture for $240.0 million.

- On April 12, 2012, we acquired a 10% ownership interest in the Texas Express Pipeline joint venture from the operator, Enterprise Products Partners, L.P., representing a total investment of approximately $85.0 million.

- On July 2, 2012, we acquired the minority ownership interests in two non-operated Mont Belvieu fractionators, or the Mont Belvieu fractionators, from DCP Midstream, LLC for aggregate consideration of $200.0 million.

- On July 3, 2012, we acquired the Crossroads processing plant and associated gathering system from Penn Virginia Resource Partners, L.P. for $63.0 million.

- On November 2, 2012, we acquired a 33.33% interest in DCP SC Texas, GP, or the Eagle Ford system, from DCP Midstream, LLC and fixed price commodity derivative hedges for a three-year period for aggregate consideration of $438.3 million. Our 33.33% interest in the construction of the Goliad 200 MMcf/d natural gas processing plant, including a two-year direct commodity price hedge, representing a total investment of approximately $97.0 million, is expected to be online in the first quarter of 2014.

- Our construction of our wholly owned Eagle 200 MMcf/d natural gas processing plant is mechanically complete and is in the process of commencing operations. Our expansion plan for the Discovery natural gas gathering pipeline system is also progressing and is expected to be completed in mid-2014. Once completed, both projects are expected to enhance our portfolio through additional fee-based margins.

Our capital markets execution has positioned us well in terms of both liquidity and cost of capital to execute our growth plans, including dropdown opportunities with DCP Midstream, LLC. In March, we raised $234.0 million, net of commissions and offering costs, through a public equity offering and $345.8 million through a public debt offering of 4.95% 10-year Senior Notes, which were used to finance our growth opportunities and repay borrowings on our Credit Agreement. On June 14, 2012, we filed a universal shelf registration statement on Form S-3 with the SEC with an unlimited offering amount, to replace an existing shelf registration statement. The universal shelf registration statement allows us to issue additional common units and debt securities. On July 2, 2012, we sold 4,989,802 common units in a private placement at a price of $35.55 per unit, and received proceeds of $173.8 million net of offering costs. During the twelve months ended December 31, 2012, we issued 1,147,654 of our common units pursuant to our equity distribution agreement, and received proceeds of $47.4 million, net of commissions and offering costs of $1.6 million. Additionally, we entered into three 2-year Term Loan agreements and borrowed $135.0 million, $140.0 million and $343.5 million to fund the cash portions of our acquisitions of the remaining 49.9% interest in East Texas, the Mont Belvieu fractionators and the Eagle Ford system, respectively. In November 2012, we issued $500.0 million of 2.50% 5-year Senior Notes, resulting in net proceeds of $493.6 million, which were used to repay the $140.0 million and $343.5 million Term Loan agreements. As of December 31, 2012, the unused capacity under the Credit Agreement was $474.0 million, which was available for general working capital purposes, providing liquidity to continue to execute on our growth plans.

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Financial results and distribution growth for the year were in line with our previously provided 2012 forecast. We raised our distributions for all four quarters, resulting in a 6.2% increase in our quarterly distribution rate for the fourth quarter of 2012 over the rate declared in the fourth quarter of 2011. The distributions reflect our business results as well as our recent execution on growth opportunities.

General Trends and Outlook

In 2013, our strategic objectives will continue to focus on maintaining stable distributable cash flows from our existing assets and executing on growth opportunities to increase our long-term distributable cash flows. We believe the key elements to stable distributable cash flows are the diversity of our asset portfolio, our significant fee-based business currently representing approximately 55% of our estimated margins, plus our highly hedged commodity position, the objective of which is to protect against downside risk in our distributable cash flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $25.0 million and $30.0 million, and approved expenditures for expansion capital of approximately $400.0 million, for the year ending December 31, 2013. Expansion capital expenditures include construction of the Texas Express Pipeline, Discovery s Keathley Canyon, and the Goliad plant within the Eagle Ford system, which are shown as investments in unconsolidated affiliates, construction of the Eagle plant, expansion and upgrades to our Southeast Texas complex, and acquisitions. The board of directors may, at its discretion, approve additional growth capital during the year.

In 2013, we expect to continue to pursue a multi-faceted growth strategy, which includes maximizing opportunities provided by our partnership with DCP Midstream, LLC, pursuing strategic and accretive third party acquisitions and capitalizing on organic expansion opportunities in order to grow our distributable cash flows. Given the significant level of growth opportunities currently in DCP Midstream, LLC s footprint, we would expect substantial emphasis on our dropdown objective over the next few years.

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

Natural Gas Gathering and Processing Margins Except for our fee-based contracts, which may be impacted by throughput volumes, our natural gas gathering and processing profitability is dependent upon commodity prices, natural gas supply, and demand for natural gas, NGLs and condensate. Commodity prices, which are impacted by the balance between supply and demand, have historically been volatile. Throughput volumes could decline, particularly in areas with lower NGL content, should natural gas prices and drilling levels continue to experience weakness. Our long-term view is that as economic conditions improve, commodity prices should remain at levels that would support continued natural gas production in the United States. During 2012, petrochemical demand remained strong for NGLs as NGLs were a lower cost feedstock when compared to crude oil derived feedstocks. We anticipate strong demand for NGLs by the petrochemical industry will continue in 2013.

NGL Logistics 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, in which higher natural gas or lower NGL prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets.

Wholesale Propane Supply and Demand 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 propane distribution customers with reliable supplies of propane during peak demand periods of tight supply, usually in the winter months when their customers consume the most propane for heating.

Factors That May Significantly Affect Our Results

Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas for all periods presented, similar to the pooling method. The financial statements of our predecessor 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 predecessor had been operated as an unaffiliated entity.

Natural Gas Services Segment

Our results of operations for our Natural Gas Services segment are impacted by (1) increases and decreases in the volume and quality of natural gas that we gather and transport through our systems, which we refer to as throughput, (2) the associated Btu content of our system throughput and our related processing volumes, (3) the prices of and relationship between commodities such as NGLs, crude oil and natural gas, (4) the operating efficiency and reliability of our processing facilities, (5) potential limitations on throughput volumes arising from downstream and infrastructure capacity constraints, (6) the terms of our processing contract arrangements with producers, and (7) increases and decreases in the volume, price and basis differentials of natural gas associated with our natural gas storage and pipeline assets, as well as our underlying derivatives associated with this business. This is not a complete list of factors that may impact our results of operations but, rather, are those we believe are most likely to impact those results.

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.

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, the commodity pricing environment at the time the contract is executed, customer requirements and competition from other midstream service providers. 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 as well as other market factors.

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

Our Natural Gas Services segment operating results 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. 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 commodity prices being at levels sufficient to provide incentives and capital for producers to explore and produce natural gas.

The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close relationship. Due to our hedging program, changes in the relationship of the price of NGLs and crude oil may cause our commodity price exposure to vary, which we have attempted to capture in our commodity price sensitivities in Quantitative and Qualitative Disclosures about Market Risk. Our results may also be impacted as a result of non-cash lower of cost or market inventory or imbalance adjustments, which occur when the market value of commodities decline below our carrying value.

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, store 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.

NGL Logistics Segment

Our NGL Logistics segment operating results are impacted by, among other things, the throughput volumes of the NGLs we transport on our NGL pipelines and the volumes of NGLs we fractionate and store. We transport, fractionate and store NGLs primarily 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. Factors that impact the supply and demand of NGLs, as described above in our Natural Gas Services segment, may also impact the throughput and volume for our NGL Logistics segment. Our results may also be impacted as a result of non-cash lower of cost or market inventory adjustments, which occur when the market value of NGLs decline below our carrying value.

Wholesale Propane Logistics Segment

Our Wholesale Propane Logistics segment operating results are impacted by our ability to provide our propane distribution customers with reliable supplies of propane. We use physical inventory, physical purchase agreements and financial derivative instruments, with DCP Midstream, LLC or third parties, which typically match the quantities of propane subject to fixed price sales agreements to mitigate our commodity price risk. Our results may also be impacted as a result of non-cash lower of cost or market inventory adjustments, which occur when the market value of propane declines below our carrying value. We generally recover lower of cost or market inventory adjustments in subsequent periods through the sale of inventory, or settlement of financial derivative instruments. There may be positive or negative impacts on sales volumes and gross margin from supply disruptions and weather conditions in the mid-Atlantic, upper midwestern 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 a recessionary environment.

The wholesale propane business is highly competitive in our market areas which include the mid-Atlantic, upper midwest and northeastern areas of the United States. Our competitors include major integrated oil and gas and energy companies, and interstate and intrastate pipelines.

Weather

The economic impact of severe weather may negatively affect the nation s short-term energy supply and demand, and may result in commodity price volatility. 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 availability and propane demand in our Wholesale Propane Logistics segment. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss in some instances, and in certain circumstances we have been unable to obtain insurance on commercially reasonable terms, if at all.

Capital Markets

Volatility 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 fund our operations through acquisitions or organic growth projects. These events may impact our counterparties ability to perform under their credit or commercial obligations. Where possible, we have obtained additional collateral agreements, letters of credit from highly rated banks, or have managed credit lines to mitigate a portion of these risks.

Impact of Inflation

Inflation has been relatively low in the United States in recent years. However, the inflation rates impacting our business fluctuate throughout the broad economic and energy business cycles. Consequently, our costs for chemicals, utilities, materials and supplies, labor and major equipment purchases may increase during periods of general business inflation or periods of relatively high energy commodity prices.

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Other

The above factors, including 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.

Recent Events

On January 28, 2013, we announced that the board of directors of DCP Midstream GP, LLC declared a quarterly distribution of $0.69 per unit, which was paid on February 14, 2013, to unitholders of record on February 7, 2013.

On February 27, 2013, we entered into an agreement with DCP Midstream, LLC to acquire an additional 46.67% interest in DCP SC Texas GP, or the Eagle Ford system, and a fixed price commodity derivative hedge for a three-year period for aggregate consideration of $626.4 million, subject to customary working capital and other purchase price adjustments. We will also contribute our proportionate share of the capital spent to date to the Eagle Ford system for the construction of the Goliad plant, plus an incremental payment of $23.3 million. DCP Midstream, LLC will also provide a twenty-seven month direct commodity price hedge (also referred to as the NGL Hedge) for our additional 46.67% interest in the project. The transaction is expected to close in March 2013.

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 NGL Logistics segment and our Wholesale Propane 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, stored 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, transporting or storing natural gas. 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/liquids 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, NGLs and condensate 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, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas, NGLs and condensate, regardless of the actual amount of the sales proceeds we receive. We keep the difference between the proceeds received and the amount remitted back to the producer. Under percent-of-liquids arrangements, we do not keep any amounts related to residue natural gas proceeds and only keep amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. 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.

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Additionally, these arrangements may include fee-based components. Our revenues under percent-of-proceeds arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly with the price of NGLs and condensate.

In addition to the above contract types, we have keep-whole arrangements, which are estimated to generate less than 5% of our gross margin. Our equity method investment in Discovery also has keep-whole arrangements. Under the terms of a keep-whole processing contract, natural gas is gathered from the producer for processing, the NGLs and condensate are sold and the residue natural gas is returned to the producer 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 and condensate extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL and condensate prices are higher relative to natural gas prices when that frac spread exceeds our operating costs. Fluctuations in commodity prices are expected to continue to impact the operating costs of these entities.

The natural gas supply for our gathering pipelines and processing plants is derived primarily from natural gas wells located in Arkansas, 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 historically 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. We had no suppliers of natural gas representing 10% or more of our total natural gas supply during the year ended December 31, 2012. 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, various DCP Midstream LLC affiliates purchase natural gas from third parties at wellheads, pipeline interconnect and pooling points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties.

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 manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage.

NGL Logistics Segment

Our pipelines, fractionation facilities and storage facility provide transportation, fractionation and storage services for customers, primarily on a fee basis. We have entered into contractual arrangements with DCP Midstream, LLC and others that generally require customers to pay us to transport or store NGLs pursuant to a fee-based rate that is applied to volumes. Therefore, the results of operations for this business segment are generally dependent upon the volume of product transported, fractionated or stored and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines, fractionated in our fractionation facilities or stored in our storage facility; rather, the customer retains title and the associated commodity price risk. DCP Midstream, LLC provides 100% of volumes transported on the Wattenberg and Seabreeze pipelines. 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, in which higher natural gas or lower NGL 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 transportation markets we serve, our pipelines are the sole pipeline facility transporting NGLs from the supply source. DCP Midstream, LLC, the largest gatherer and processor in the DJ Basin, delivers NGLs to our fractionation facilities under a long-term fractionation agreement. Our storage facility in Marysville, Michigan provides storage and related services primarily to depositories operating in the liquid hydrocarbons industry.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the mid-Atlantic, upper 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 mid-Atlantic, 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 four primary suppliers of propane, two of which are affiliated entities, represented approximately 88% of our propane supplied during the year ended December 31, 2012. The propane supply agreement with Spectra Energy expired on April 30, 2012. We primarily sell propane on a wholesale basis to propane distributors who in turn resell propane to their customers. We also sell propane in the wholesale market.

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 propane distribution customers with reliable supplies of propane during periods of tight supply, such as the winter months when their 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 purchases of propane from us in the summer. We believe these factors allow us to maintain our generally favorable relationships with our customers.

We manage our wholesale propane margins by selling propane to propane distributors under annual sales agreements negotiated each spring which specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. 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.

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) adjusted EBITDA, (5) adjusted segment EBITDA; and (6) distributable cash flow. Gross margin, segment gross margin, adjusted segment gross margin, adjusted EBITDA, adjusted segment EBITDA, and distributable cash flow are not measures under accounting principles generally accepted in the United States of America, or

GAAP. To the extent permitted, we present certain non-GAAP measures and reconciliations of those 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 and storage 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 and gas on our pipelines are substantially dependent upon the quantities of NGLs and gas produced at our processing plants, as well as NGLs and gas produced at other processing plants that have pipeline connections with our NGL and gas pipelines. We regularly monitor producer activity in the areas we serve and in which our pipelines are located, and pursue opportunities to connect new supply to these pipelines. We also monitor our inventory in our NGL and gas storage facilities, as well as overall demand for storage based on seasonal patterns and other market factors such as weather and overall demand.

Reconciliation of Non-GAAP Measures

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, including commodity derivative activity, 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 commodity derivative losses, less non-cash commodity 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, operating revenues, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States of America, or GAAP.

Adjusted EBITDA We define adjusted EBITDA as net income or loss attributable to partners less interest income, noncontrolling interest in depreciation and income tax expense and non-cash commodity derivative gains, plus interest expense, income tax expense, depreciation and amortization expense and non-cash commodity derivative losses. Our adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate this measure in the same manner.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, 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.

Adjusted Segment EBITDA We define adjusted segment EBITDA for each segment as segment net income or loss attributable to partners less non-cash commodity derivative gains for that segment, plus depreciation and amortization expense and non-cash commodity derivative losses for that segment, adjusted for any noncontrolling interest on depreciation and amortization expense for that segment. Our adjusted segment EBITDA may not be comparable to similarly titled measures of other companies because they may not calculate adjusted segment EBITDA in the same manner.

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Adjusted segment EBITDA should not be considered in isolation or as an alternative to our financial measures presented in accordance with GAAP, including operating revenues, net income or loss attributable to Partners, or any other measure of performance presented in accordance with GAAP.

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

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing methods or capital structure;
- viability and performance of acquisitions and capital expenditure projects and the overall rates of return on investment opportunities; and
- in the case of Adjusted EBITDA, 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.

The accompanying schedules provide reconciliations of gross margin, segment gross margin, and adjusted segment EBITDA to its most directly comparable GAAP financial measure.

Distributable Cash Flow 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, net income attributable to noncontrolling interest net of depreciation and income tax, 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 or earnings capacity. 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 and interest rates. Distributable Cash Flow is used as a supplemental liquidity and performance 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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Our gross margin, segment gross margin, adjusted segment gross margin and adjusted segment EBITDA 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,		
	2012	2011	2010
		(Millions)	
Reconciliation of net income attributable to partners to gross margin:			
Net income attributable to partners	$ 168.0	$ 120.8	$ 91.2
Interest expense	42.2	33.9	29.1
Income tax expense	1.0	0.5	1.5
Operating and maintenance expense	123.2	125.7	98.3
Depreciation and amortization expense	63.4	100.6	88.1
General and administrative expense	45.8	48.3	45.8
Other income	(0.5)	(0.5)	(2.0)
Other income affiliate			(3.0)
Step acquisition equity interest re-measurement gain			(9.1)
Earnings from unconsolidated affiliates	(28.9)	(22.7)	(23.8)
Net income attributable to noncontrolling interests	5.0	18.8	9.2
Gross margin	$ 419.2	$ 425.4	$ 325.3
Non-cash commodity derivative mark-to-market (a)	$ 21.3	$ 42.1	$ (9.8)
Reconciliation of segment net income attributable to partners to segment gross margin:			
Natural Gas Services segment:			
Segment net income attributable to partners	$ 179.5	$ 142.0	$ 133.8
Operating and maintenance expense	92.4	94.7	82.0
Depreciation and amortization expense	54.7	89.5	83.5
Other income			(2.0)
Earnings from unconsolidated affiliates	(17.6)	(22.7)	(23.0)
Net income attributable to noncontrolling interests	5.0	18.8	9.2
Segment gross margin	$ 314.0	$ 322.3	$ 283.5
Non-cash commodity derivative mark-to-market (a)	$ 19.8	$ 41.8	$ (8.8)
NGL Logistics segment:			
Segment net income attributable to partners	$ 53.0	$ 28.4	$ 16.5
Operating and maintenance expense	16.1	15.9	3.7
Depreciation and amortization expense	6.2	8.2	2.6
Step acquisition equity interest re-measurement gain			(9.1)
Other income	(0.5)	(0.5)	
Earnings from unconsolidated affiliates	(11.3)		(0.8)
Segment gross margin	$ 63.5	$ 52.0	$ 12.9
Wholesale Propane Logistics segment:			
Segment net income attributable to partners	$ 24.5	$ 33.1	$ 17.4
Operating and maintenance expense	14.7	15.1	12.6
Depreciation and amortization expense	2.5	2.9	1.9

Other income affiliate			(3.0)
Segment gross margin	$ 41.7	$ 51.1	$ 28.9
Non-cash commodity derivative mark-to-market (a)	$ 1.5	$ 0.3	$ (1.0)

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

	Year Ended December 31, 2012	2011 (Millions)	2010
Reconciliation of segment net income attributable to partners to adjusted segment EBITDA:			
Natural Gas Services segment:			
Segment net income attributable to partners	$ 179.5	$ 142.0	$ 133.8
Non-cash commodity derivative mark-to-market	(19.8)	(41.8)	8.8
Depreciation and amortization expense	54.7	89.5	83.5
Noncontrolling interest on depreciation and income tax	(1.4)	(13.8)	(13.3)
Adjusted segment EBITDA	$ 213.0	$ 175.9	$ 212.8
NGL Logistics segment:			
Segment net income attributable to partners	$ 53.0	$ 28.4	$ 16.5
Depreciation and amortization expense	6.2	8.2	2.6
Adjusted segment EBITDA	$ 59.2	$ 36.6	$ 19.1
Wholesale Propane Logistics segment:			
Segment net income attributable to partners	$ 24.5	$ 33.1	$ 17.4
Non-cash commodity derivative mark-to-market	(1.5)	(0.3)	1.0
Depreciation and amortization expense	2.5	2.9	1.9
Adjusted segment EBITDA	$ 25.5	$ 35.7	$ 20.3

Operating and Maintenance and General and Administrative Expense Operating and maintenance expenses are costs associated with the operation of a specific asset and are primarily comprised of direct labor, ad valorem taxes, repairs and maintenance, lease expenses, utilities and contract services. These expenses fluctuate depending on the activities performed during a specific period. General and administrative expenses are as follows:

	Year Ended December 31, 2012	2011 (Millions)	2010
General and administrative expense	$ 16.2	$ 18.9	$ 14.3
General and administrative expense affiliate:			
Omnibus Agreement	25.4	10.2	9.9
Other DCP Midstream, LLC	3.9	18.9	21.4
Other affiliate	0.3	0.3	0.2
Total affiliate	29.6	29.4	31.5
Total	$ 45.8	$ 48.3	$ 45.8

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. 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.

On January 3, 2012, we extended the omnibus agreement through December 31, 2012 for an annual fee of $17.6 million, with the primary increase resulting from the acquisition of the remaining 49.9% interest in East Texas. On March 30, 2012, in conjunction with our acquisition of the remaining 66.67% interest in Southeast Texas, we increased the annual fee we pay to DCP Midstream, LLC under the agreement by $10.3

million, prorated for the remainder of the 2012 calendar year. These fees were previously allocated to East Texas and Southeast Texas. In July 2012, in conjunction with our acquisition of the minority interests in the Mont Belvieu fractionators, we increased the annual fee we pay to DCP Midstream, LLC by $0.2 million. As a result of these

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transactions, the annual fee payable in future years to DCP Midstream, LLC will be $28.1 million, unless there are further adjustments made as a result of future transactions or otherwise. 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 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; and

- 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.

Before the addition of East Texas and Southeast Texas to the Omnibus Agreement, East Texas and Southeast Texas incurred general and administrative expenses directly from DCP Midstream, LLC. During the years ended December 31, 2011 and 2010, East Texas incurred $7.5 million and $7.8 million, respectively, and during the years ended December 31, 2012, 2011 and 2010, Southeast Texas incurred $2.5 million, $10.0 million and $12.1 million, respectively, which includes expenses for our predecessor operations. General and administrative expenses incurred by East Texas and Southeast Texas effective January 3, 2012 and March 30, 2012, respectively, are covered by the Omnibus Agreement.

In addition to the Omnibus Agreement and amounts incurred by East Texas and Southeast Texas, we incurred other fees with DCP Midstream, LLC, which includes expenses for our predecessor operations, of $1.4 million, $1.4 million and $1.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. These amounts include allocated expenses, including professional services, insurance, internal audit and various other corporate functions.

On February 14, 2013, we entered into a Services Agreement with DCP Midstream, LLC, which replaces the Omnibus Agreement, whereby DCP Midstream, LLC will continue to provide us with the general and administrative services previously provided under the Omnibus Agreement. The annual amounts payable in future years to DCP Midstream, LLC under the Services Agreement will be consistent with the fee structure previously payable under the Omnibus Agreement, and will be $28.6 million for 2013. Pursuant to the Services Agreement, we will reimburse DCP Midstream, LLC for expenses and expenditures incurred or payments made on our behalf.

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.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2012, 2011 and 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Year Ended December 31,			Variance 2012 vs. 2011		Variance 2011 vs. 2010	
	2012 (a)(b)	2011 (a)(b)(c)	2010 (a)(b)(c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)						
Operating revenues (d):							
Natural Gas Services (e)	$ 1,242.7	$ 1,670.4	$ 1,617.6	$ (427.7)	(26)%	$ 52.8	3%
NGL Logistics	63.5	56.6	17.6	6.9	12%	39.0	222%
Wholesale Propane Logistics	414.7	633.6	473.2	(218.9)	(35)%	160.4	34%
Intra-segment eliminations	(0.2)	(2.2)		2.0	91%	(2.2)	*
Total operating revenues	1,720.7	2,358.4	2,108.4	(637.7)	(27)%	250.0	12%
Gross margin (f):							
Natural Gas Services	314.0	322.3	283.5	(8.3)	(3)%	38.8	14%
NGL Logistics	63.5	52.0	12.9	11.5	22%	39.1	303%
Wholesale Propane Logistics	41.7	51.1	28.9	(9.4)	(18)%	22.2	77%
Total gross margin	419.2	425.4	325.3	(6.2)	(1)%	100.1	31%
Operating and maintenance expense	(123.2)	(125.7)	(98.3)	(2.5)	(2)%	27.4	28%
Depreciation and amortization expense	(63.4)	(100.6)	(88.1)	(37.2)	(37)%	12.5	14%
General and administrative expense	(45.8)	(48.3)	(45.8)	(2.5)	(5)%	2.5	5%
Step acquisition equity interest remeasurement gain			9.1		%	(9.1)	(100)%
Other income	0.5	0.5	2.0		%	(1.5)	(75)%
Other income affiliates			3.0		%	(3.0)	(100)%
Earnings from unconsolidated affiliates (h)	28.9	22.7	23.8	6.2	27%	(1.1)	(5)%
Interest expense	(42.2)	(33.9)	(29.1)	8.3	24%	4.8	16%
Income tax expense	(1.0)	(0.5)	(1.5)	0.5	100%	(1.0)	(67)%
Net income attributable to noncontrolling interests	(5.0)	(18.8)	(9.2)	(13.8)	(73)%	9.6	104%
Net income attributable to partners	$ 168.0	$ 120.8	$ 91.2	$ 47.2	39%	$ 29.6	32%
Other data:							
Non-cash commodity derivative mark-to-market	$ 21.3	$ 42.1	$ (9.8)	$ (20.8)	(49)%	$ 51.9	*
Natural gas throughput (MMcf/d) (g)	1,667	1,415	1,481	252	18%	(66)	(4)%
NGL gross production (Bbls/d) (g)	65,610	53,064	55,845	12,546	24%	(2,781)	(5)%
NGL pipelines throughput (Bbls/d) (g)	78,508	62,555	38,282	15,953	26%	24,273	63%
Propane sales volume (Bbls/d)	19,111	24,743	22,350	(5,632)	(23)%	2,393	11%

* Percentage change is not meaningful.

(a) Includes the results of the Raywood processing plant and Liberty gathering system since June 29, 2010, the date of acquisition, the remaining 49.9% interest in East Texas, since January 3, 2012, the date of acquisition, and the Crossroads processing plant since July 3, 2012, the date of acquisition, in our Natural Gas Services segment.

Includes the results of Atlantic Energy, since July 30, 2010, the date of acquisition, in our Wholesale Propane Logistics segment.

Includes the results of our Wattenberg pipeline acquired from Buckeye Partners, L.P, since January 28, 2010, the date of acquisition, and an additional 50% interest in Black Lake acquired from an affiliate of BP PLC, since July 30, 2010, the date of acquisition, in our NGL Logistics segment. The acquisition of an additional 50% interest in Black Lake brought our ownership interest in Black Lake to 100%. Prior to our

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acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary.

Includes the results of our Marysville NGL storage facility and our DJ Basin NGL fractionators since the dates of acquisition of December 30, 2010 and March 24, 2011, respectively.

(b) On January 1, 2011, we acquired an initial 33.33% interest in Southeast Texas for $150.0 million. On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative hedge instruments related to the Southeast Texas storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas for the years ended December 31, 2012, 2011 and 2010.

(c) We utilize commodity derivative instruments to provide stability to distributable cash flows for our proportionate ownership in East Texas as well as all other natural gas services assets. We did not utilize commodity derivative instruments for the proportionate interest in East Texas owned by DCP Midstream, LLC prior to our acquisition of the remaining 49.9% interest in January 2012. As such, the portion of East Texas owned by DCP Midstream, LLC in the periods presented in 2011 and 2010 is unhedged. Our consolidated results depict 49.9% of East Texas unhedged in 2011 and 2010 corresponding with DCP Midstream, LLC s ownership interest in East Texas.

(d) Operating revenues include the impact of commodity derivative activity.

(e) Includes the effect of the acquisition of the NGL commodity derivative hedge instruments associated with the Southeast Texas storage business, the Eagle Ford system and the Goliad plant acquired from DCP Midstream, LLC in March, November and December 2012, respectively.

(f) 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.

(g) Includes our proportionate share of the throughput volumes and NGL production of Collbran, Jackson Pipeline Company, or Jackson, Discovery, and the Eagle Ford system.

For periods prior to July 30, 2010, includes our 50% share of the throughput volumes for Black Lake.

(h) Earnings from unconsolidated affiliates include our proportionate earnings of Discovery, the Mont Belvieu fractionators, Crosspoint, and the Eagle Ford system, which includes the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

For periods prior to July 30, 2010, includes earnings for Black Lake, which include the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

Included in the consolidated results of operations are the noncontrolling interests which represent the third party or affiliate interests in the non-wholly-owned entities that we consolidate, which include East Texas, for the years ended December 31, 2011 and 2010, and Collbran, for the years ended December 31, 2012, 2011 and 2010, among others. Our results of operations reflect 100% of all consolidated assets, including noncontrolling interests.

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

Total Operating Revenues Total operating revenues decreased $637.7 million in 2012 compared to 2011 primarily as a result of the following:

- $375.7 million decrease primarily attributable to lower NGL and natural gas prices;

- $237.6 million decrease attributable to reduced Wholesale Propane Logistics segment volumes as a result of a lack of demand due to the industry s excess inventory resulting from record warm weather last heating season, and lower propane prices; and

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$86.5 million decrease primarily due to lower volumes, lower gas storage revenue and the East Texas recovery settlement in 2011, partially offset by our acquisition of the Crossroads system in July 2012.

These decreases were partially offset by:

$62.1 million increase related to commodity derivative activity including $83.2 million increase in settled derivatives offset by $21.1 million change in non-cash derivative mark-to-market losses. Included in our derivative activity are an increase in unrealized losses of $38.0 million and an increase in realized gains of $33.0 million from the predecessor s Southeast Texas storage business.

Gross Margin Gross margin decreased $6.2 million in 2012 compared to 2011, primarily as a result of the following:

$9.4 million decrease for our Wholesale Propane Logistics segment primarily from a lack of demand due to the industry s excess inventory resulting from record warm weather last heating season; and

$8.3 million decrease for our Natural Gas Services segment, primarily related to lower commodity prices, decreased volumes and differences in gas quality across certain assets, and the East Texas recovery settlement in 2011, partially offset by increased commodity derivative activity and our acquisition of the Crossroads system in July 2012.

These decreases were partially offset by:

$11.5 million increase for our NGL Logistics segment as a result of increased throughput and rates on certain of our pipelines, the completion of the Wattenberg expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2012 compared to 2011 as result of timing of expenditures partially offset by growth.

Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful lives of our assets.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing our 33.33% interest in the Eagle Ford system, 40% ownership of Discovery, 20% ownership of the Mont Belvieu 1 Fractionator, 12.5% ownership of the Mont Belvieu Enterprise Fractionator, and 50% ownership in CrossPoint, increased in 2012 compared to 2011 primarily as a result of our acquisition of the Mont Belvieu Fractionators in July 2012 and the Eagle Ford system in November 2012. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Net income attributable to noncontrolling interests Net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of our acquisition of the remaining 49.9% of East Texas.

Year Ended December 31, 2011 vs. Year Ended December 31, 2010

Total Operating Revenues Total operating revenues increased in 2011 compared to 2010 primarily as a result of the following:

$160.7 million increase primarily as a result of our acquisition of Atlantic Energy, as well as higher propane prices for our Wholesale Propane Logistics segment;

$44.4 million increase primarily attributable to higher crude and NGL prices and the East Texas recovery settlement, partially offset by reduced volumes on our Southeast Texas and Pelico systems;

$40.1 million increase in transportation, processing and other revenue, which represents our fee-based revenues, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL fractionators and an additional 50% interest in Black Lake, and the Wattenberg capital expansion project; and

$4.8 million increase related to commodity derivative activity. This includes an increase of $54.2 million in unrealized gains due to movements in forward prices of commodities, offset by an increase in cash settlement losses of $49.4 million.

Gross Margin Gross margin increased in 2011 compared to 2010, primarily as a result of the following:

- $38.8 million increase for our Natural Gas Services segment primarily as a result of higher crude oil and NGL prices, commodity derivative activities, the East Texas recovery settlement, and increased volumes and NGL production across certain assets, partially offset by decreased margins in our Southeast Texas storage business, planned turnaround activity at East Texas and an extended planned third party outage at our Wyoming asset;

- $39.1 million increase for our NGL Logistics segment primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL fractionators and an additional 50% interest in Black Lake, and the Wattenberg capital expansion project; and

- $22.2 million increase for our Wholesale Propane Logistics segment primarily as a result of higher unit margins, increased volumes and our acquisition of Atlantic Energy. 2010 results reflect a planned outage related to our Providence terminal inspection.

Operating and Maintenance Expense Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, Atlantic Energy, an additional 50% interest in Black Lake and the DJ Basin NGL fractionators, the Wattenberg capital expansion project, and planned turnaround activity and environmental remediation at East Texas.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of a full year of depreciation related to the Raywood processing plant and Liberty gathering system acquired in June 2010, and our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake, the DJ Basin NGL fractionators, Atlantic Energy, and the Wattenberg capital expansion project.

Step acquisition equity interest re-measurement gain The non-cash step acquisition equity interest re-measurement gain in 2010 resulted from our acquisition of an additional 50% interest in Black Lake bringing our ownership interest in Black Lake to 100% in our NGL Logistics segment. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary. As a result of acquiring an additional 50% interest in Black Lake, we remeasured our initial 50% equity interest in Black Lake to its fair value, and recognized a non-cash gain of $9.1 million.

Other income Other income in 2010 related to our reassessment of the fair value of contingent consideration for our acquisition of the Raywood processing plant and Liberty gathering system in June 2010, and an additional 5% interest in Collbran from Delta Petroleum Company, or Delta, in February 2010.

Other income affiliates Other income affiliates results for 2010 reflect a $3.0 million payment received in the second quarter from Spectra Energy, a supplier for our Wholesale Propane Logistics segment, related to an amendment of a supply agreement to shorten the term of the agreement by two years.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates decreased in 2011 compared to 2010 primarily due to our additional interest in Black Lake. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction, we account for Black Lake as a consolidated subsidiary. Commodity derivative activity related to our unconsolidated affiliates is included in segment gross margin.

Net income attributable to noncontrolling interests Net income attributable to noncontrolling interests increased in 2011 compared to 2010 primarily as a result of the East Texas recovery settlement.

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Results of Operations — Natural Gas Services Segment

This segment consists of our Northern Louisiana system, the Southern Oklahoma system, a 40% interest in Discovery, our Southeast Texas system, a 75% operating interest in our Colorado system, our Wyoming system, our East Texas system, our Michigan system, and our 33.33% interest in our Eagle Ford system:

	Year Ended December 31,			Variance 2012 vs. 2011		Variance 2011 vs. 2010	
	2012 (a)(b)(c)	2011 (a)(b)(c)	2010 (a)(b)(c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)						
Operating revenues:							
Sales of natural gas, NGLs and condensate	$ 1,068.7	$ 1,541.3	$ 1,496.7	$ (472.6)	(31)%	$ 44.6	3%
Transportation, processing and other	121.7	120.2	117.1	1.5	1%	3.1	3%
Gains from commodity derivative activity (d)	52.3	8.9	3.8	43.4	488%	5.1	134%
Total operating revenues	1,242.7	1,670.4	1,617.6	(427.7)	(26)%	52.8	3%
Purchases of natural gas and NGLs	928.7	1,348.1	1,334.1	(419.4)	(31)%	14.0	1%
Segment gross margin (e)	314.0	322.3	283.5	(8.3)	(3)%	38.8	14%
Operating and maintenance expense	(92.4)	(94.7)	(82.0)	(2.3)	(2)%	12.7	15%
Depreciation and amortization expense	(54.7)	(89.5)	(83.5)	(34.8)	(39)%	6.0	7%
Other income (expense)			2.0		%	(2.0)	(100)%
Earnings from unconsolidated affiliates (g)	17.6	22.7	23.0	(5.1)	(22)%	(0.3)	(1)%
Segment net income	184.5	160.8	143.0	23.7	15%	17.8	12%
Segment net income attributable to noncontrolling interests	(5.0)	(18.8)	(9.2)	(13.8)	(73)%	9.6	104%
Segment net income attributable to partners	$ 179.5	$ 142.0	$ 133.8	$ 37.5	26%	$ 8.2	6%
Other data:							
Non-cash commodity derivative mark-to-market	19.8	41.8	(8.8)	(22.0)	(53)%	50.6	*
Natural gas throughput (MMcf/d) (f)	1,667	1,415	1,481	252	18%	(66)	(4)%
NGL gross production (Bbls/d) (f)	65,610	53,064	55,845	12,546	24%	(2,781)	(5)%

(a) Includes the results of the Raywood processing plant and Liberty gathering system since June 29, 2010, the date of acquisition, and the Crossroads processing plant since July 3, 2012, the date of acquisition.

(b) On January 1, 2011, we acquired an initial 33.33% interest in Southeast Texas for $150.0 million. On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative hedge instruments related to the Southeast Texas storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas for the years ended December 31, 2012, 2011 and 2010.

(c) We utilize commodity derivative instruments to provide stability to distributable cash flows for our proportionate ownership in East Texas as well as all other natural gas services assets. We did not utilize commodity derivative instruments for the proportionate interest in East Texas owned by DCP Midstream, LLC prior to our acquisition of the remaining 49.9% interest in

January 2012. As such, the portion of East Texas owned by DCP Midstream, LLC in the periods presented in 2011 and 2010 is unhedged. Our consolidated results depict 49.9% of East Texas unhedged in 2011 and 2010 corresponding with DCP Midstream, LLC s ownership interest in East Texas.

(d) Includes the effect of the acquisition of the NGL Hedge, contributed by DCP Midstream, LLC in April 2009, and the NGL commodity derivative hedge instruments associated with the Eagle Ford system, including the Goliad plant, acquired from DCP Midstream, LLC in November and December 2012, respectively, and the Southeast Texas storage business acquired from DCP Midstream, LLC in March 2012. The NGL Hedge is a fixed price natural gas liquids derivative by NGL component, which commenced in April 2009 and expired in March 2010.

(e) 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.

(f) Includes our proportionate share of the throughput volumes and NGL production of Collbran, Jackson, Discovery, and the Eagle Ford system.

(g) Earnings from unconsolidated affiliates include our proportionate earnings of Discovery, Crosspoint, and the Eagle Ford system, which includes the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

Total Operating Revenues Total operating revenues decreased $427.7 million in 2012 compared to 2011 primarily as a result of the following:

- $241.1 million decrease attributable to the impact of lower commodity prices on our gathering and processing business;

- $167.1 million decrease primarily attributable to decreased prices for physical sales related to our natural gas storage and pipeline assets, as well as a decrease in volumes;

- $57.1 million decrease primarily attributable to decreased volumes across certain assets, differences in gas quality and extensive turnaround activity at East Texas; and

- $5.8 million decrease as a result of the East Texas recovery settlement in 2011.

These decreases were partially offset by:

- $43.4 million increase related to commodity derivative activity. This includes a change in unrealized commodity derivative activity in 2012 compared to 2011 of $22.2 million due to movements in forward prices of commodities, and realized cash settlement gains in 2012 compared to realized cash settlement losses in 2011 for a net increase of $65.6 million. Included in our derivative activity are an increase in unrealized losses of $38.0 million and an increase in realized gains of $33.0 million from the predecessor s Southeast Texas storage business.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased $419.4 million in 2012 compared to 2011 primarily as a result of lower commodity prices and decreased volumes across certain assets, partially offset by our acquisition of the Crossroads system in July 2012.

Segment Gross Margin Segment gross margin decreased $8.3 million in 2012 compared to 2011, primarily as a result of the following:

- $39.6 million decrease as a result of lower commodity prices;

- $6.3 million decrease primarily attributable to decreased volumes and differences in gas quality across certain assets, and extensive turnaround activity at East Texas; and

- $5.8 million decrease as a result of the East Texas recovery settlement in 2011.

These decreases were partially offset by:

- $43.4 million increase related to commodity derivative activities as discussed in the Operating Revenues section above.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2012 compared to 2011 primarily as a result of timing of expenditures, partially offset by our acquisition of the Crossroads system in July 2012.

Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful lives of our assets.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing our 33.33% interest in the Eagle Ford system, 40% ownership of Discovery and 50% ownership in CrossPoint, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes on Discovery, partially offset by the acquisition of the Eagle Ford system in November 2012 and the timing of expenditures at Discovery. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Segment net income attributable to noncontrolling interests Segment net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of the acquisition of the remaining 49.9% of East Texas.

Natural Gas Throughput Natural gas transported, processed and/or treated increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of East Texas, the Crossroads system, and our 33.33% interest in the Eagle Ford system, partially offset by decreased volumes across certain assets and turnaround at East Texas.

NGL Gross Production NGL production increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of East Texas, the Crossroads system, and our 33.33% interest in the Eagle Ford system, partially offset by decreased volumes and differences in gas quality across certain assets and turnaround at East Texas.

Year Ended December 31, 2011 vs. Year Ended December 31, 2010

Included in the consolidated results of operations are the noncontrolling interests which represent the third party or affiliate interests in the non-wholly-owned entities that we consolidate, which include East Texas and Collbran, among others. Our results of operations reflect 100% of all consolidated assets, including noncontrolling interests.

Total Operating Revenues Total operating revenues increased in 2011 compared to 2010, primarily as a result of the following:

- $154.4 million increase attributable to higher crude and NGL prices, which impact both sales and purchases;
- $5.1 million increase related to commodity derivative activity. This includes an increase of $52.9 million in unrealized gains due to movements in forward prices of commodities, offset by an increase in cash settlement losses of $47.8 million; and
- $6.6 million increase attributable to the East Texas recovery settlement.

These increases were partially offset by:

- $113.3 million decrease attributable to reduced volumes on our Southeast Texas and Pelico systems, partially offset by increased volumes across certain assets and an increase in transportation, processing and other revenue.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased in 2011 compared to 2010, primarily as a result of increases in commodity prices, partially offset by reduced volumes on our Southeast Texas system, which impact both purchases and sales.

Segment Gross Margin Segment gross margin increased in 2011 compared to 2010, primarily as a result of the following:

$34.3 million increase as a result of higher crude oil and NGL prices;

$6.6 million increase attributable to the East Texas recovery settlement; and

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- $5.1 million increase related to commodity derivative activity as discussed in the Operating Revenues section above.

These increases were partially offset by:

- $7.2 million decrease primarily attributable to decreased margins in our Southeast Texas storage business, planned turnaround activity at East Texas and an extended planned third party outage at our Wyoming asset, partially offset by increased volumes and NGL production across certain assets and changes in contract terms.

Operating and Maintenance Expense Operating and maintenance expense increased in 2011 compared to 2010 due to planned turnaround activity and environmental remediation at East Texas.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2011 compared to 2010 primarily due to a full year of depreciation related to the Raywood processing plant and Liberty gathering system acquired in June 2010 and completed capital projects.

Other income Other income in 2010 related to our reassessment of the fair value of contingent consideration for our acquisition of the Raywood processing plant and Liberty gathering system in June 2010, and an additional 5% interest in Collbran from Delta Petroleum Company, or Delta, in February 2010.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, remained relatively constant in 2011 compared to 2010. Commodity derivative activity related to our unconsolidated affiliates is included in segment gross margin.

Segment net income attributable to noncontrolling interests Segment net income attributable to noncontrolling interests increased in 2011 compared to 2010, with $4.6 million due to the East Texas recovery settlement.

Natural Gas Throughput Natural gas transported, processed and/or treated decreased in 2011 compared to 2010 primarily as a result of reduced volumes on our Pelico system.

NGL Gross Production NGL production decreased in 2011 compared to 2010 primarily as a result of differences in gas quality.

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Results of Operations   NGL Logistics Segment

This segment includes our Seabreeze, Wilbreeze, Wattenberg and Black Lake transportation pipelines, our 10% interest in the Texas Express NGL pipeline, our Marysville NGL storage facility, our DJ Basin NGL fractionators and our minority ownership interests in the Mont Belvieu fractionators:

	Year Ended December 31,			Variance 2012 vs. 2011		Variance 2011 vs. 2010	
	2012 (b)(c)	2011 (b)(c)	2010 (c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of NGLs	$	$ 4.8	$ 4.7	$ (4.8)	(100)%	$ 0.1	2%
Transportation, processing and other	63.5	51.8	12.9	11.7	23%	38.9	302%
Total operating revenues	63.5	56.6	17.6	6.9	12%	39.0	222%
Purchases of NGLs		4.6	4.7	(4.6)	(100)%	(0.1)	(2)%
Segment gross margin (a)	63.5	52.0	12.9	11.5	22%	39.1	303%
Operating and maintenance expense	(16.1)	(15.9)	(3.7)	0.2	1%	12.2	330%
Depreciation and amortization expense	(6.2)	(8.2)	(2.6)	(2.0)	(24)%	5.6	215%
Step acquisition equity interest re-measurement gain			9.1		%	(9.1)	(100)%
Other income	0.5	0.5			%	0.5	100%
Earnings from unconsolidated affiliates (d)	11.3		0.8	11.3	100%	(0.8)	(100)%
Segment net income attributable to partners	$ 53.0	$ 28.4	$ 16.5	$ 24.6	87%	$ 11.9	72%
Operating data:							
NGL pipelines throughput (Bbls/d) (c)	78,508	62,555	38,282	15,953	26%	24,273	63%

(a) Segment gross margin consists of total operating revenues less purchases of NGLs. Please read Reconciliation of Non-GAAP Measures above.

(b) Includes the results of our Marysville NGL storage facility and our DJ Basin NGL fractionators since the dates of acquisition of December 30, 2010 and March 24, 2011, respectively.

(c) Includes the results of our Wattenberg pipeline and our Black Lake pipeline since the dates of acquisition of January 28, 2010 and July 30, 2010, respectively.

(d) Includes our share, based on our ownership percentage, of the throughput volumes and earnings of the Mont Belvieu fractionators.

For periods prior to July 30, 2010, includes our 50% share of the throughput volumes and earnings for Black Lake. Black Lake s earnings included the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

Total Operating Revenues Total operating revenues increased in 2012 compared to 2011 as result of increased throughput and rates on certain of our pipelines, the completion of the Wattenberg capital expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Segment Gross Margin Segment gross margin increased in 2012 compared to 2011 as result of increased throughput and rates on certain of our pipelines, the completion of the Wattenberg capital expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Operating and Maintenance Expense Operating and maintenance expense increased in 2012 compared to 2011 due to the completion of the Wattenberg capital expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by timing of expenditures.

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Depreciation and Amortization Expense Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful lives of our assets.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates, representing 20% ownership of the Mont Belvieu 1 Fractionator and 12.5% ownership of the Mont Belvieu Enterprise Fractionator, increased in 2012 compared to 2011 as a result the acquisition of the Mont Belvieu Fractionators in July 2012.

NGL Pipelines Throughput NGL pipelines throughput increased in 2012 compared to 2011 as a result of volume growth on our pipelines and the completion of the Wattenberg capital expansion project, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Year Ended December 31, 2011 vs. Year Ended December 31, 2010

Total Operating Revenues Total operating revenues increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL fractionators and an additional 50% interest in Black Lake, and the Wattenberg capital expansion project.

Segment Gross Margin Segment gross margin increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL fractionators and an additional 50% interest in Black Lake, the Wattenberg capital expansion project, and increased throughput on our pipelines.

Operating and Maintenance Expense Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake and the DJ Basin NGL fractionators, and the Wattenberg capital expansion project.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL fractionators, an additional 50% interest in Black Lake, and the Wattenberg capital expansion project.

Step acquisition equity interest re-measurement gain The non-cash step acquisition equity interest re-measurement gain in 2010 resulted from our acquisition of an additional 50% interest in Black Lake bringing our ownership interest in Black Lake to 100%. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary. As a result of acquiring an additional 50% interest in Black Lake, we remeasured our initial 50% equity interest in Black Lake to its fair value, and recognized a non-cash gain of $9.1 million.

Earnings from Unconsolidated Affiliates Earnings from unconsolidated affiliates decreased in 2011 compared to 2010 reflecting the impact of our additional interest in Black Lake. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction, we account for Black Lake as a consolidated subsidiary.

NGL Pipelines Throughput NGL pipelines throughput increased in 2011 compared to 2010 as a result of the Wattenberg capital expansion project, volume growth on our pipelines and our acquisition an additional 50% interest in Black Lake.

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Results of Operations Wholesale Propane Logistics Segment

This segment consists of our propane terminals, which include six owned and operated rail terminals, one owned marine terminal, one leased marine terminal, one pipeline terminal and access to several open-access propane pipeline terminals:

	Year Ended December 31,			Variance 2012 vs. 2011		Variance 2011 vs. 2010	
	2012 (b)	2011 (b)	2010 (b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of propane	$ 397.2	$ 634.6	$ 473.8	$ (237.4)	(37)%	$ 160.8	34%
Transportation, processing and other		0.2	0.3	(0.2)	(100)%	(0.1)	(33)%
Gain (losses) from commodity derivative activity	17.5	(1.2)	(0.9)	18.7	*	(0.3)	(33)%
Total operating revenues	414.7	633.6	473.2	(218.9)	(35)%	160.4	34%
Purchases of propane	373.0	582.5	444.3	(209.5)	(36)%	138.2	31%
Segment gross margin (a)	41.7	51.1	28.9	(9.4)	(18)%	22.2	77%
Operating and maintenance expense	(14.7)	(15.1)	(12.6)	(0.4)	(3)%	2.5	20%
Depreciation and amortization expense	(2.5)	(2.9)	(1.9)	(0.4)	(14)%	1.0	53%
Other income affiliates			3.0		%	(3.0)	(100)%
Segment net income attributable to partners	$ 24.5	$ 33.1	$ 17.4	$ (8.6)	(26)%	$ 15.7	90%
Other Data:							
Non-cash commodity derivative mark-to-market	1.5	0.3	(1.0)	1.2	400%	1.3	*
Propane sales volume (Bbls/d)	19,111	24,743	22,350	(5,632)	(23)%	2,393	11%

* Percentage change is not meaningful.

(a) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of propane. Please read Reconciliation of Non-GAAP Measures above.

(b) Includes the results of our Chesapeake terminal, acquired July 30, 2010 from Atlantic Energy.

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

Total Operating Revenues Total operating revenues decreased $218.9 million in 2012 compared to 2011, primarily as a result of the following:

- $152.2 million decrease attributable to reduced sales volumes primarily as a result of a lack of demand due to the industry s excess inventory resulting from record warm weather last heating season; and

- $85.4 million decrease attributable to lower propane prices.

These decreases were partially offset by:

$18.7 million increase related to a change in unrealized commodity derivative activity of $1.1 million and a change in realized commodity derivative activity of $17.6 million.

Purchases of Propane Purchases of propane decreased in 2012 compared to 2011 primarily due to reduced volumes as a result of inventory build resulting from record warm weather last heating season and lower propane prices, partially offset by a non-cash lower of cost or market inventory adjustment of $15.4 million in 2012, offset by a significant recovery through the sale of inventory.

Segment Gross Margin Segment gross margin decreased in 2012 compared to 2011 primarily from a lack of demand due to the industry s excess inventory resulting from record warm weather last heating season and lower per unit margins. A non-cash lower of cost or market inventory adjustment of $15.4 million was offset by a significant recovery through the sale of inventory and hedging activity.

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Operating and Maintenance Expense Operating and maintenance expense remained relatively constant in 2012 compared to 2011.

Depreciation and Amortization Expense Depreciation and amortization expense remained relatively constant in 2012 compared to 2011.

Propane Sales Volume Propane sales volumes decreased in 2012 compared to 2011 as a result of a lack of demand due to the industry s excess inventory resulting from record warm weather last heating season.

Year Ended December 31, 2011 vs. Year Ended December 31, 2010

Total Operating Revenues Total operating revenues increased in 2011 compared to 2010, primarily as a result of the following:

$106.8 million increase attributable to higher propane prices, which impacts both purchases and sales; and

$53.9 million increase primarily as a result of our acquisition of Atlantic Energy.

These increases were partially offset by:

$0.3 million decrease related to commodity derivative activity.

Purchases of Propane Purchases of propane increased in 2011 compared to 2010 due to higher propane prices, which impact both sales and purchases, and our acquisition of Atlantic Energy.

Segment Gross Margin Segment gross margin increased in 2011 compared to 2010, primarily as a result of higher unit margins, increased volumes and our acquisition of Atlantic Energy. 2010 results reflect a planned outage related to our Providence terminal inspection.

Operating and Maintenance Expense Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy.

Other income affiliates Other income affiliates results for 2010 reflect a $3.0 million payment received in the second quarter from Spectra Energy, a supplier for our Wholesale Propane Logistics segment, related to an amendment of a supply agreement to shorten the term of the agreement by two years.

Propane Sales Volume Propane sales volumes increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy. 2010 results reflect a planned outage related to our Providence terminal inspection.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

cash generated from operations;

cash distributions from our unconsolidated affiliates;

- borrowings under our revolving Credit Agreement;
- borrowings under term loans;
- issuance of additional common 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;

- quarterly distributions to our unitholders and general partner;
- contributions to our unconsolidated affiliates to finance our share of their capital expenditures;
- business and asset acquisitions; and
- 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.

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.

We routinely evaluate opportunities for strategic investments or acquisitions. Future material investments or acquisitions may require that we obtain additional capital, assume third party debt or incur other long-term obligations. We have the option to utilize both equity and debt instruments as vehicles for the long-term financing of our investment activities and acquisitions.

On November 10, 2011, we entered into a senior unsecured revolving credit agreement with capacity of $1.0 billion, which matures on November 10, 2016 (Credit Agreement). The Credit Agreement replaced our Amended and Restated Credit Agreement dated as of June 21, 2007 (the Prior Credit Agreement), which had a total borrowing capacity of $850.0 million. The initial borrowing under the Credit Agreement was used to repay the Partnership s indebtedness under the Prior Credit Agreement. The Credit Agreement will be used for ongoing working capital requirements and for other general partnership purposes including acquisitions.

As of December 31, 2012, the outstanding balance on the Credit Agreement was $525.0 million resulting in unused revolver capacity of $474.0 million, which was available for general working capital purposes.

Our borrowing capacity is currently 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 the Credit Agreement will not mature prior to the November 10, 2016 maturity date. As of February 22, 2013, we had approximately $424.0 million of unused capacity under the Credit Agreement.

In November 2012, we issued $500.0 million of 2.50% 5-year Senior Notes due December 1, 2017. We received proceeds of $493.6 million, net of underwriters fees, related expenses and unamortized discount.

In November 2012, we entered into a 2-year Term Loan Agreement and borrowed $343.5 million to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford system. In July 2012, we entered into a 2-year Term Loan Agreement and borrowed $140.0 million to fund the cash portion of the acquisition of the Mont Belvieu fractionators. In November 2012, we repaid both term loans with proceeds from our 2.50% 5-year Senior Notes.

In March 2012, we issued $350.0 million of 4.95% 10-year Senior Notes due April 1, 2022. We received proceeds of $345.8 million, net of underwriters fees, related expenses and unamortized discount, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Credit Agreement and our January 3, 2012 Term Loan.

In January 2012, we entered into a 2-year Term Loan Agreement and borrowed $135.0 million which was used to fund the cash portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

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 could limit our borrowing capacity, raise our financing costs, as well as impact our compliance with our financial covenant requirements under our Credit Agreement.

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 portion of our anticipated commodity price risk

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associated with the equity volumes from our gathering and processing activities through 2016 with fixed price commodity swaps and collar arrangements. For additional information regarding our derivative activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Commodity Cash Flow Protection Activities.

In August 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, common units having an aggregate offering amount of up to $150.0 million. As of December 31, 2012, approximately $69.5 million aggregate offering price of our common units remains available for sale pursuant to this equity distribution agreement. During the three months ended December 31, 2012, we issued 254,265 of our common units pursuant to the equity distribution agreement, and received proceeds of $10.0 million, net of commissions and offering costs of $0.7 million. During the year ended December 31, 2012, we issued 1,147,654 of our common units pursuant to the equity distribution agreement, and received proceeds of $47.4 million, net of commissions and offering costs of $1.6 million. During the year ended December 31, 2011, we issued 761,285 of our common units pursuant to this equity distribution agreement, and received proceeds of $30.2 million from the issuance of these common units, net of commissions and offering costs of $1.2 million.

In November 2012, we issued 1,912,663 common units to DCP Midstream, LLC as partial consideration for the acquisition of a 33.33% interest in the Eagle Ford system.

In July 2012, we issued 1,536,098 common units to DCP Midstream, LLC as partial consideration for the Mont Belvieu fractionators.

In July 2012, we closed a private placement of equity with a group of institutional investors in which we sold 4,989,802 common units at a price of $35.55 per unit, for a total of $177.4 million, and received proceeds of $173.8 million net of offering costs.

In June 2012, we filed a universal shelf registration statement on Form S-3 with the SEC with an unlimited offering amount, to replace an existing shelf registration statement. The universal shelf registration statement allows us to issue additional common units and debt securities. As of February 22, 2013, we have issued no equity securities under this registration statement. Our 2.50% 5-year Senior Notes were issued under this registration statement.

In March 2012, we issued 5,148,500 common units at $47.42 per unit. We received proceeds of $234.0 million, net of offering costs.

In March 2012, we issued 1,000,417 common units to DCP Midstream, LLC as partial consideration for the remaining 66.67% interest in Southeast Texas.

In January 2012, we issued 727,520 common units to DCP Midstream, LLC as partial consideration for the remaining 49.9% interest in East Texas.

In March 2011, we issued 3,596,636 common units at $40.55 per unit. We received proceeds of $139.7 million, net of offering costs.

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 22, 2013, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $25.0 million in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with these counterparties. We pay DCP Midstream, LLC a fee of 0.50% per annum on these guarantees. These parental guarantees reduce the amount of cash we may be required to post as collateral. As of February 22, 2013, 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 zero in the event DCP Midstream, LLC s credit rating were to fall below investment grade.

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, inventory levels and 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.

We had working capital of $75.7 million as of December 31, 2012, compared to a working capital deficit of $26.8 million as of December 31, 2011 as a result of timing of payments for trade payables. Included in these working capital amounts are net derivative working capital assets of $18.4 million and net derivative working capital liabilities of $18.7 million as of December 31, 2012 and December 31, 2011, respectively. The change in working capital is primarily attributable to the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

As of December 31, 2012, we had $1.3 million in cash and cash equivalents. Of this balance, $0.8 million was held by subsidiaries we do not wholly own, which we consolidate in our financial results. Other than the cash held by these subsidiaries, this cash balance was available for general partnership purposes.

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

	Year Ended December 31,		
	2012	2011	2010
		(Millions)	
Net cash provided by operating activities	$ 124.9	$ 260.8	$ 162.4
Net cash used in investing activities	$ (1,070.5)	$ (340.7)	$ (345.5)
Net cash provided by financing activities	$ 939.3	$ 80.8	$ 187.7

Our predecessor s sources of liquidity, prior to its 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 net changes in parent advances to predecessors from 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 received net cash for settlement of our commodity derivative instruments of approximately $48.5 million and $34.6 million for the years ended December 31, 2012 and 2011, respectively, and received cash of $14.8 million for the year ended December 31, 2010, approximately $6.2 million of which was associated with rebalancing our portfolio. During the year ended December 31, 2012, we made state tax payments of $0.7 million, and no federal tax payments. During the year ended December 31, 2011, we made federal and state tax payments of $29.3 million and $0.3 million, respectively, related to our acquisition of Marysville and the conversion of the entity s organizational structure from a corporation to a limited liability company. In addition, we received $3.6 million from DCP Midstream, LLC, related to the sale of surplus equipment, for the year ended December 31, 2010.

We and our predecessors received cash distributions from unconsolidated affiliates of $29.3 million, $25.3 million and $30.0 million during the years ended December 31, 2012, 2011 and 2010, respectively. Distributions exceeded earnings by $0.4 million for the year ended December 31, 2012.

Net Cash Used in Investing Activities Net cash used in investing activities during 2012 was comprised of: (1) acquisition expenditures of $687.4 million, of which $282.2 million is related to our acquisition of

33.33% interest in the Eagle Ford system, $192.5 million is related to our acquisition of the remaining 66.67% interest in Southeast Texas, $119.9 million related to our acquisition of the remaining 49.9% interest in East Texas, $63.0 million related to our acquisition of Crossroads, and $29.8 million related to our acquisition of the Mont Belvieu fractionators; (2) capital expenditures of $200.4 million (of which our portion was $185.0 million and the reimbursable projects portion was $15.4 million); and (3) investments in unconsolidated affiliates of $184.0 million; partially offset by (4) a return of investment from unconsolidated affiliate of $1.0 million; and (5) proceeds from sales of assets of $0.3 million.

Net cash used in investing activities during 2011 was comprised of: (1) capital expenditures of $165.7 million (our portion of which was $146.5 million and the noncontrolling interest holders portion was $19.2 million), which includes $25.2 million of capital expenditures related to our Eagle Plant construction; (2) acquisition expenditures of $114.3 million, representing the carrying value of the net assets acquired, related to our acquisition of an initial 33.33% interest in Southeast Texas; (3) acquisition expenditures of $29.6 million related to our acquisition of our DJ Basin NGL fractionators, $23.4 million related to our acquisition of Eagle Plant construction work in progress, and a payment of $7.5 million to the seller of Michigan Pipeline & Processing, LLC in relation to our contingent payment agreement; and (4) investments in unconsolidated affiliates of $7.0 million; partially offset by (5) proceeds from sales of assets of $5.2 million; and (6) a return of investment from unconsolidated affiliates of $1.6 million.

Net cash used in investing activities during 2010 was comprised of: (1) acquisition expenditures of $282.1 million related to our acquisition of Atlantic Energy, the Wattenberg NGL pipeline, Marysville, the Raywood processing plant and Liberty gathering system, and an additional 55% interest in Black Lake; (2) capital expenditures of $75.9 million (our portion of which was $61.1 million and the noncontrolling interest holders portion was $14.8 million); and (3) investments in unconsolidated affiliates of $2.3 million; partially offset by (4) net proceeds from sale of available-for-sale securities of $10.1 million; (5) proceeds from sale of assets of $3.5 million; and (6) a return of investment from Discovery of $1.2 million.

Net Cash Provided By Financing Activities Net cash provided by financing activities during 2012 was comprised of: (1) proceeds from debt of $2,664.8 million, offset by repayments of $1,791.5 million, for net borrowing of debt of $873.3 million; (2) proceeds from the issuance of common units net of offering costs of $445.2 million; and (3) contributions from DCP Midstream, LLC of $10.3 million; partially offset by (4) excess purchase price over acquired net assets of $192.8 million; (5) distributions to our unitholders and general partner of $181.3 million; (6) change in advances to predecessor from DCP Midstream, LLC of $11.5 million; (7) payment of deferred financing costs of $7.7 million; and (8) distributions to noncontrolling interests of $6.2 million.

During 2012, total outstanding indebtedness under our $1.0 billion Credit Agreement, which includes borrowings under our revolving credit facility and letters of credit issued under the Credit Agreement, was not less than $268.1 million and did not exceed $576.1 million. The weighted-average indebtedness outstanding under the Agreement Facility was $495.8 million, $369.3 million, $321.2 million and $455.0 million for the first, second, third and fourth quarters of 2012, respectively.

We had unused capacity, which is available for commitments under the Credit Agreement, of $731.9 million, $648.9 million, $699.0 million and $474.0 million at the end of the first, second, third and fourth quarters of 2012, respectively.

During 2012, we had the following net movements on our revolving credit facility:

- $63.0 million borrowing to fund the acquisition of the Crossroads system; and
- $199.0 million net borrowings for general working capital purposes; partially offset by
- $234.0 million repayment with proceeds from the issuance of 5,148,500 common units in March 2012.

Net cash provided by financing activities during 2011 was comprised of: (1) proceeds from the issuance of common units, net of offering costs, of $169.7 million; (2) net borrowing of debt of $99.0 million; (3) contributions from noncontrolling interests of $18.3 million; and (4) net change in advances to predecessor from DCP Midstream, LLC of $10.9 million; partially offset by (5) distributions to our unitholders and general

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partner of $132.4 million; (6) distributions to noncontrolling interests of $44.8 million; (7) excess purchase price over the acquired net assets of Southeast Texas of $35.7 million; and (8) payment of deferred financing costs of $4.2 million.

During 2011, total outstanding indebtedness under our $1.0 billion Credit Agreement, which includes borrowings under our revolving credit facility and letters of credit issued under the Credit Agreement, was not less than $425.5 million and did not exceed $591.1 million. The weighted-average indebtedness outstanding under the revolving credit facility was $519.1 million, $454.1 million, $483.8 million and $517.1 million for the first, second, third and fourth quarters of 2011, respectively.

We had unused capacity, which is available for commitments under the Credit Agreement of $423.5 million, $387.9 million, $372.9 million and $501.9 million at the end of the first, second, third and fourth quarters of 2011, respectively.

During 2011, we had the following net movements on our revolving credit facility:

- $150.0 million borrowing to fund the acquisition of our initial 33.33% interest in Southeast Texas;
- $30.0 million borrowing to fund the purchase of the DJ Basin NGL fractionators;
- $29.6 million borrowing to fund the Marysville tax payment;
- $23.4 million borrowing to fund the purchase of certain tangible assets and land located in the Eagle Ford Shale; and
- $5.7 million net borrowings; partially offset by
- $139.7 million repayment financed by the issue of 3,596,636 common units in March 2011.

Net cash provided by financing activities during 2010 was comprised of: (1) borrowings of $868.2 million; (2) proceeds from the issuance of common units net of offering costs of $189.3 million; (3) net change in advances to predecessor from DCP Midstream, LLC of $82.3 million; (4) contributions from noncontrolling interests of $13.8 million; and (5) contributions from DCP Midstream, LLC of $0.6 million; partially offset by (6) repayments of debt of $833.4 million; (7) distributions to our unitholders and general partner of $101.9 million; (8) distributions to noncontrolling interests of $25.6 million; (9) purchase of additional interest in a subsidiary of $3.5 million; and (10) payment of deferred financing costs of $2.1 million.

During 2010, total outstanding indebtedness under our $850.0 million Prior Credit Agreement, which includes borrowings under our revolving credit facility, our term loan and letters of credit issued under the Prior Credit Agreement, was not less than $300.5 million and did not exceed $722.4 million. The weighted-average indebtedness outstanding under the revolving credit facility was $622.5 million, $625.9 million, $634.7 million and $347.9 million for the first, second, third and fourth quarters of 2010, respectively.

We had unused capacity, which is available commitments under the Prior Credit Agreement of $209.3 million, $234.6 million, $486.5 million and $419.9 million at the end of the first, second, third and fourth quarters of 2010, respectively.

During 2010, we had the following net movements on our revolving credit facility:

- $247.7 million repayment financed by the issue of $250.0 million of 3.25% Senior Notes due October 1, 2015;

$93.1 million repayment financed by the issue of 2,990,000 common units in August 2010; and

$96.2 million repayment financed by the issue of 2,875,000 common units in November 2010; partially offset by

$66.3 million borrowing to fund the acquisition of Atlantic Energy, which includes $17.3 million for propane inventory and working capital;

$16.3 million net borrowings for general corporate purposes;

$22.0 million borrowing to fund the acquisition of the Wattenberg pipeline;

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- $16.6 million borrowing to fund the acquisition of an additional 55% interest in Black Lake;
- $100.8 million borrowing to fund the acquisition of Marysville, which includes $6.0 million for inventory and working capital; and
- $10.0 million borrowing to fund repayment of our term loan.

During 2010, we had a repayment of $10.0 million on our term loan under the Prior Credit Agreement and released $10.0 million of restricted investments which were required as collateral for the facility.

We expect to continue to use cash provided by operating 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 Statement 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, including certain system integrity and safety improvements, or acquire or construct new capital assets if such expenditures are made to maintain, including over the long-term, our operating or earnings capacity; 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 or earnings capacity.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $25.0 million and $30.0 million, and approved expenditures for expansion capital of approximately $400.0 million, for the year ending December 31, 2013. Expansion capital expenditures include construction of the Texas Express Pipeline, Discovery s Keathley Canyon, and the Goliad plant within the Eagle Ford system, which are shown as investments in unconsolidated affiliates, construction of the Eagle plant, expansion and upgrades to our Southeast Texas complex, and acquisitions. The board of directors may, at its discretion, approve additional growth capital during the year.

The following table summarizes our maintenance and expansion capital expenditures for our consolidated entities.

	Year Ended December 31, 2012			Year Ended December 31, 2011		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
		(Millions)			(Millions)	
Our portion	$ 17.5	$ 167.5	$ 185.0	$ 12.9	$ 133.6	$ 146.5
Noncontrolling interest portion and reimbursable projects (a)	6.0	9.4	15.4	5.5	13.7	19.2
Total	$ 23.5	$ 176.9	$ 200.4	$ 18.4	$ 147.3	$ 165.7

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	Year Ended December 31, 2010		
	Maintenance Capital Expenditures	Expansion Capital Expenditures (Millions)	Total Consolidated Capital Expenditures
Our portion	$ 6.9	$ 54.2	$ 61.1
Noncontrolling interest portion and reimbursable projects (a)	6.4	8.4	14.8
Total	$ 13.3	$ 62.6	$ 75.9

(a) In conjunction with our acquisitions of our East Texas and Southeast Texas systems, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on capital projects. These reimbursements are for certain capital projects which have commenced within three years from the respective acquisition dates.

In addition, we invested cash in unconsolidated affiliates of $184.0 million, $7.0 million and $2.3 million during the years ended December 31, 2012, 2011 and 2010, respectively.

Capital expenditures increased in 2012 compared to 2011 primarily as a result of construction of our Eagle Plant and acquisition integration costs.

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 will include debt and common unit issuances, to fund our acquisition and expansion capital expenditures.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our Credit Agreement, the issuance of additional partnership units and the issuance of long-term debt. If these sources are not sufficient, we will reduce our discretionary spending.

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, including payment to our general partner related to our incentive distribution rights, of $181.3 million, $132.4 million and $101.9 million during 2012, 2011 and 2010, respectively. We intend to continue making quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

Description of the Credit Agreement On November 10, 2011, we entered a senior unsecured revolving credit agreement with capacity of $1.0 billion, which matures on November 10, 2016 (Credit Agreement). The Credit Agreement replaced our Amended and Restated Credit Agreement dated as of June 21, 2007 (the Prior Credit Agreement), which had a total borrowing capacity of $850.0 million. As of December 31, 2012, the outstanding balance on the Credit Agreement was $525.0 million resulting in unused capacity of $474.0 million, which was available for general working capital purposes.

Our obligations under the Credit Agreement are unsecured. The unused portion of the Credit Agreement may be used for letters of credit up to a maximum of $500.0 million of outstanding letters of credit. At December 31, 2012 and 2011, we had outstanding letters of credit issued under the Credit Agreement and Prior Credit Agreement of $1.0 million and $1.1 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 Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.25% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A. s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.25% based on our current credit rating. The revolving credit facility incurs an annual facility fee of 0.25% based on our current credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

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.

Description of Debt Securities On November 27, 2012, we issued $500.0 million of our 2.50% 5-year Senior Notes due December 1, 2017. We received net proceeds of $493.6 million, net of underwriters fees, related expenses and unamortized discounts of $6.4 million, which net proceeds were used to repay our then-outstanding term loans. Interest on the notes will be paid semi-annually on June 1 and December 1 of each year, commencing June 1, 2013. The notes will mature on December 1, 2017, unless redeemed prior to maturity. The underwriters fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

On March 13, 2012, we issued $350.0 million of our 4.95% 10-year Senior Notes due April 1, 2022. We received net proceeds of $345.8 million, net of underwriters fees, related expenses and unamortized discounts of $4.2 million, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. The notes will mature on April 1, 2022, unless redeemed prior to maturity. The underwriters fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

On September 30, 2010, we issued $250.0 million of our 3.25% Senior Notes due October 1, 2015. We received net proceeds of $247.7 million, net of underwriters fees, related expense and unamortized discounts of $2.3 million, which we used to repay funds borrowed under the revolver portion of our Credit Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters fees and related expense are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

The notes are senior unsecured obligations, ranking equally in right of payment with our existing unsecured indebtedness, including indebtedness under our Credit Agreement. We are not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at our option.

Description of Term Loan Agreements On November 2, 2012, we borrowed $343.5 million on a 2-year Term Loan Agreement (the $343.5 million Term Loan) to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford system. On July 2, 2012, we entered into a 2-year Term Loan Agreement and borrowed $140.0 million (the $140 million Term Loan) to fund the cash portion of the acquisition of the Mont Belvieu fractionators. In November 2012, we repaid both the term loans with proceeds from our 2.50% 5-year Senior Notes.

On January 3, 2012, we entered into a 2-year Term Loan Agreement and borrowed $135.0 million which was used to fund the cash portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations A summary of our total contractual cash obligations as of December 31, 2012, is as follows:

	Payments Due by Period				
	Total	**2013**	**2014-2015**	**2016-2017**	**2018 and Thereafter**
			(Millions)		
Long-term debt (a)	$ 1,886.2	$ 44.5	$ 329.1	$ 1,084.6	$ 428.0
Operating lease obligations (b)	24.3	10.8	9.1	3.5	0.9
Purchase obligations (c)	222.5	114.5	63.1	44.9	
Other long-term liabilities (d)	17.9		0.5	0.2	17.2
Total	$ 2,150.9	$ 169.8	$ 401.8	$ 1,133.2	$ 446.1

(a) Includes interest payments on debt that has been swapped to a fixed-rate obligation and on debt securities that have been issued. These interest payments are $44.5 million, $79.1 million, $59.6 million, and $78.0 million for 2013, 2014-2015, 2016-2017, and 2018 and thereafter, respectively. Interest payments on debt

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that has not been swapped to a fixed-rate obligation are not included as these payments are based on floating interest rates and we cannot determine with accuracy the periodic repayment dates or the amounts of the interest payments.

(b) Our operating lease obligations are contractual obligations, and primarily consist of our leased marine propane terminal and railcar leases, both of which provide supply and storage infrastructure for our Wholesale Propane Logistics business. Operating lease obligations also include firm transportation arrangements and natural gas storage for our Pelico system. The firm transportation arrangements supply off-system natural gas to Pelico and the natural gas storage arrangement enables us to maximize the value between the current price of natural gas and the futures market price of natural gas.

(c) Our purchase obligations are contractual obligations and include purchase orders for capital expenditures, various non-cancelable commitments to purchase physical quantities of propane supply for our Wholesale Propane Logistics business and other items. For contracts where the price paid is based on an index, the amount is based on the forward market prices as of December 31, 2012. 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.

(d) Other long-term liabilities include $16.9 million of asset retirement obligations and $1.0 million of environmental reserves recognized in the consolidated balance sheet at December 31, 2012.

Off-Balance Sheet Arrangements

We have no items that are classified as off balance sheet obligations.

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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 of NGLs and natural gas, 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 commodity prices were to decrease by 10% below our December 31, 2012 weighted-average cost, our net income would be affected by approximately $7.5 million.
Impairment of Goodwill		
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 primarily use a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and 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. For certain reporting units, we may elect to first assess qualitative factors to determine whether it is more likely than not that the fair value of our reporting units is less than the carrying value. We have not recorded any impairment charges on goodwill during the year ended December 31, 2012.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
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 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.	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. 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.	Using the impairment review methodology described herein, we have not recorded any impairment charges on long-lived assets during the year ended December 31, 2012. 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 impairment charge.
Impairment of Investments in Unconsolidated Affiliates		
We evaluate our investments in unconsolidated affiliates 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 unconsolidated affiliates 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 any impairment charges on investments in unconsolidated affiliates during the year ended December 31, 2012. If the estimated fair value of our unconsolidated affiliates is less than the carrying value, we would recognize an impairment loss for the excess of the carrying value over the estimated fair value.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
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 the expected relationship 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, 2012 would have affected net income by approximately $9.0 million based on our net derivative position for the year ended December 31, 2012.
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 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.	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 tenure of our employees and the achievement of certain performance targets over the performance period.	If actual results are not consistent with our assumptions and judgments or our assumptions and estimates change due to new information, we may experience material changes in compensation expense.
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, 2012 would have no impact on our net income.

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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 a portion of the effects of identified risks. In general, we attempt to mitigate a portion of the 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 counterparty credit risk and commodity price risk, including monitoring exposure limits.

See Note 11, Risk Management and Hedging Activities, 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 marketers and industrial end-users. In the NGL Logistics Segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Our principal customers in the Wholesale Propane Logistics segment are primarily propane distributors. 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 agreement 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 that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates and locking in rates on our anticipated future fixed-rate debt, respectively. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations.

At December 31, 2012, we had interest rate swap agreements extending through June 2014 totaling $150.0 million, which are designated as cash flow hedges. Based on our current operations, we believe our interest rate swap agreements mitigate a portion of our interest rate risk associated with our variable-rate debt.

At December 31, 2011, we had interest rate swap agreements totaling $450.0 million, of which we had designated $425.0 million as cash flow hedges and account for the remaining $25.0 million under the mark-to-market method of accounting. As we generally expect to have variable-rate debt levels equal to or exceeding our swap positions during their term, the entire $450.0 million of these arrangements mitigated our interest rate risk through June 2012, with $150.0 million extending from June 2012 through June 2014.

Effectiveness of our interest rate swap agreements designated as cash flow hedges 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 and are reclassified into earnings as the hedged transactions impact earnings. Ineffective portions of changes in fair value are recognized in earnings.

At December 31, 2012, the effective weighted-average interest rate on our outstanding debt was 3.10%, taking into account our interest rate swap agreements totaling $150.0 million.

Based on the annualized unhedged borrowings under our Credit Agreement of $375.0 million as of December 31, 2012, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $1.9 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, sales and storage 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 and storage 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, costless collars 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 fixed price swaps and collar arrangements to mitigate a portion of the effect pricing fluctuations may have on the value of our assets and operations. Depending on our risk management objectives, we may periodically settle a portion of these instruments prior to their maturity.

We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices, however there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. During 2012, the relationship of NGLs to crude oil has been lower than historical relationships, however a significant amount of our NGL hedges from 2012 through 2015 are direct product hedges. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps.

The derivative financial instruments we have entered into are typically referred to as swap contracts and collar arrangements. The 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.

We also use commodity collar arrangements, which entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the floor price stated in the contract. Conversely, if the reference price is above the ceiling price stated in the contract, we are required to make payment at settlement to the counterparty. If the reference price is between the floor price and the ceiling price, no payment will be made at the settlement of the contract.

We use the mark-to-market method of accounting for all commodity cash flow protection activities, 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 tables set forth additional information about our fixed price swaps, and our collar arrangements used to mitigate a portion of our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering operations, as of February 22, 2013:

Commodity Swaps

Period		Commodity	Notional Volume - (Short)/Long Positions	Reference Price	Price Range
January 2013	December 2014	Natural Gas	(500) MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a)	$5.06/MMBtu
January 2013	December 2014	Natural Gas	(1,000) MMBtu/d	Texas Gas Transmission Price (b)	$4.87/MMBtu
January 2013	December 2013	Natural Gas	(9,185) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	$4.50/MMBtu
January 2014	December 2014	Natural Gas	(8,401) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	$4.50/MMBtu
January 2015	December 2015	Natural Gas	(9,244) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	$4.50/MMBtu
January 2013	December 2013	Natural Gas	(2,467) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	$4.50/MMBtu
January 2014	December 2014	Natural Gas	(3,511) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	$4.50/MMBtu
January 2015	December 2015	Natural Gas	(4,803) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	$4.50/MMBtu
January 2013	December 2014	Natural Gas	500 MMBtu/d	Texas Gas Transmission Price (b)	$4.93/MMBtu
January 2013	December 2013	NGL s	(6,367) Bbls/d	Mt.Belvieu Non-TET (d)	$.64-2.60/Gal
January 2014	December 2014	NGL s	(7,082) Bbls/d	Mt.Belvieu Non-TET (d)	$.64-2.60/Gal
January 2015	March 2015	NGL s	(8,125) Bbls/d	Mt.Belvieu Non-TET (d)	$.64-2.60/Gal
April 2015	December 2015	NGL s	(6,400) Bbls/d	Mt.Belvieu Non-TET (d)	$.64-1.89/Gal
January 2013	December 2013	Crude Oil	(2,351) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$67.60-$99.85/Bbl
January 2014	December 2014	Crude Oil	(1,601) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$74.90-$96.08/Bbl
January 2015	December 2015	Crude Oil	(1,101) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$92.00-$100.04/Bbl
January 2016	December 2016	Crude Oil	(500) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$101.30/Bbl

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

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

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

(d) The average monthly OPIS price for Mt. Belvieu Non-TET.

(e) The Inside FERC monthly published index price for Houston Ship Channel.

(f) The Inside FERC monthly published index price for Henry Hub.

Commodity Collar Arrangements

Period		Commodity	Notional Volume	Reference Price	Collar Price Range
January 2013	December 2013	Crude Oil	400 Bbls/d (a)	Asian-pricing of NYMEX crude oil futures (b)	$80.00 - $96.50/Bbl

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(a) Reflects separate purchased put and sold call contracts, resulting in a collar arrangement.

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

Our sensitivities for 2013 as shown in the table below are estimated based on our average estimated commodity price exposure and commodity cash flow protection activities for the calendar year 2013, and exclude the impact from non-cash mark-to-market on our commodity derivatives. We utilize crude oil and NGL derivatives to mitigate a portion of our commodity price exposure for NGLs, and show 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.

Commodity Sensitivities Excluding Non-Cash Mark-To-Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners (Millions)
Natural gas prices	$ 0.10	MMBtu	$ 0.2
Crude oil prices (a)	$ 1.00	Barrel	$ 0.5
NGL to crude oil price relationship (b)	1 percentage point change	Barrel	$ 2.0

(a) Assuming 45% NGL to crude oil price relationship. At crude oil prices outside of our collar range of approximately $80.00 to $97.40, this sensitivity decreases by $0.1 million.

(b) Assuming 45% NGL to crude oil price relationship and $90.00 /Bbl crude oil price. Generally, this sensitivity changes by $0.2 million for each $10.00/Bbl change in the price of crude oil. As crude oil prices increase from $90.00/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 $90.00/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 2013 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 Attributable to Partners) (Millions)	
Natural gas prices	$	0.10	MMBtu	$	0.9
Crude oil prices	$	1.00	Barrel	$	2.0
NGL prices	$	0.01	Gallon	$	3.1

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 relationship 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 related to the price of crude oil. 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. 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 portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing activities through 2016.

Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices, however there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. During 2012, the relationship of NGLs to crude oil has been lower than historical relationships, however a significant amount of our NGL hedges in 2012 through 2015 are direct product hedges. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps.

Based on historical trends, we generally expect NGL prices to directionally follow changes in crude oil prices over the long-term. However, the pricing relationship between NGLs and crude oil may vary, as we believe crude oil prices 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, whereas NGL prices are more correlated to supply and U.S. petrochemical demand. We believe that future natural gas prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production and drilling activity of exploration and production companies and imports of liquid natural gas, or LNG, from foreign locations. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also further reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall relative to demand levels.

Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

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The following tables set forth additional information about our derivative instruments used to mitigate a portion of our natural gas price risk associated with our natural gas storage operations, as of December 31, 2012:

Inventory

Period	Commodity	Notional Volume - Long Positions		Fair Value (millions)	Weighted Average Price
December 31, 2012	Natural Gas	6,160,653 MMBtu	s	$ 19.9	$ 3.23/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume -(Short)/Long Positions		Fair Value (millions)	Price Range
January 2013-November 2013	Natural Gas	(40,475,000) MMBtu	s	$ 4.8	$ 3.19-$3.94/MMBtu
January 2013-November 2013	Natural Gas	33,367,500 MMBtu	s	$ (5.0)	$ 3.20-$3.90/MMBtu

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 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 relationship 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, 2012				
Sources of Fair Value	Total	Maturity in 2013	Maturity in 2014-2015 (Millions)	Maturity in 2016-2017	Maturity in 2018 and Thereafter
Prices supported by quoted market prices and other external sources	$ (23.8)	$ (21.4)	$ (4.8)	$ 2.4	$
Prices based on models or other valuation techniques	$ 104.3	$ 39.8	$ 64.5	$	$

Total	$	80.5	$	18.4	$	59.7	$	2.4	$	

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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, positions in natural gas, NGLs and crude oil. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service 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 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We 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 $252,999,000 and $139,512,000 at December 31, 2012 and 2011, respectively, and in Discovery s net income of $12,091,000, $20,323,000, and $20,570,000 for the years ended December 31, 2012, 2011, and 2010, 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 the 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, such consolidated statements present fairly, in all material respects, the financial position of the Company as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

The consolidated financial statements give retrospective effect for the Company s acquisition of the 100% ownership interest in DCP Southeast Texas Holdings, GP, of which 33.33% and 66.67% was acquired on January 1, 2011 and March 30, 2012, respectively, from DCP Midstream, LLC, as a combination of entities under common control, which has been accounted for in a manner similar to a pooling of interests, as described in Note 1 to the consolidated financial statements.

Also as described in Note 1 to the consolidated financial statements, the portion of the accompanying consolidated financial statements for the three years in the period ended December 31, 2012 attributable to DCP Southeast Texas Holdings, GP has 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 DCP Southeast Texas Holdings, GP had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to, DCP Midstream, LLC as a whole.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2012, based on the criteria established in the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2013 expressed an unqualified opinion on the Company s internal control over financial reporting based on our audit.

/s/ Deloitte & Touche LLP

Denver, Colorado

February 27, 2013

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1.3	$ 7.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.3 million and $0.3 million, respectively	95.0	108.6
Affiliates	86.3	106.2
Inventories	74.7	87.9
Unrealized gains on derivative instruments	49.4	41.2
Other	2.4	2.2
Total current assets	309.1	353.7
Property, plant and equipment, net	1,727.4	1,499.4
Goodwill	153.8	153.8
Intangible assets, net	136.9	145.3
Investments in unconsolidated affiliates	558.0	107.1
Unrealized gains on derivative instruments	69.8	6.4
Other long-term assets	17.0	11.7
Total assets	$ 2,972.0	$ 2,277.4
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 112.6	$ 231.7
Affiliates	33.7	46.8
Unrealized losses on derivative instruments	31.0	59.9
Capital spending accrual	17.3	10.5
Other	38.8	31.6
Total current liabilities	233.4	380.5
Long-term debt	1,620.3	746.8
Unrealized losses on derivative instruments	7.7	32.8
Other long-term liabilities	27.4	19.0
Total liabilities	1,888.8	1,179.1
Commitments and contingent liabilities:		
Equity:		
Predecessor equity		257.4
Common unitholders (61,346,058 and 44,848,703 units issued and outstanding, respectively)	1,062.8	654.4
General partner	(0.3)	(4.7)
Accumulated other comprehensive loss	(14.7)	(21.2)
Total partners equity	1,047.8	885.9
Noncontrolling interests	35.4	212.4
Total equity	1,083.2	1,098.3

Total liabilities and equity	$ 2,972.0	$ 2,277.4

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2012	2011	2010
	(Millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 735.0	$ 1,067.6	$ 1,050.9
Sales of natural gas, propane, NGLs and condensate to affiliates	730.9	1,110.9	924.2
Transportation, processing and other	147.1	138.8	108.1
Transportation, processing and other to affiliates	37.9	33.4	22.2
Gains from commodity derivative activity, net	17.2	6.8	5.3
Gains (losses) from commodity derivative activity, net affiliates	52.6	0.9	(2.3)
Total operating revenues	1,720.7	2,358.4	2,108.4
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	1,050.3	1,485.8	1,504.9
Purchases of natural gas, propane and NGLs from affiliates	251.2	447.2	278.2
Operating and maintenance expense	123.2	125.7	98.3
Depreciation and amortization expense	63.4	100.6	88.1
General and administrative expense	16.2	18.9	14.3
General and administrative expense affiliates	29.6	29.4	31.5
Step acquisition equity interest re-measurement gain			(9.1)
Other income	(0.5)	(0.5)	(2.0)
Other income affiliates			(3.0)
Total operating costs and expenses	1,533.4	2,207.1	2,001.2
Operating income	187.3	151.3	107.2
Interest expense	(42.2)	(33.9)	(29.1)
Earnings from unconsolidated affiliates	28.9	22.7	23.8
Income before income taxes	174.0	140.1	101.9
Income tax expense	(1.0)	(0.5)	(1.5)
Net income	173.0	139.6	100.4
Net income attributable to noncontrolling interests	(5.0)	(18.8)	(9.2)
Net income attributable to partners	168.0	120.8	91.2
Net income attributable to predecessor operations	(2.6)	(20.4)	(43.2)
General partner s interest in net income	(41.2)	(25.2)	(16.9)
Net income allocable to limited partners	$ 124.2	$ 75.2	$ 31.1
Net income per limited partner unit basic	$ 2.28	$ 1.73	$ 0.86
Net income per limited partner unit diluted	$ 2.28	$ 1.72	$ 0.86
Weighted-average limited partner units outstanding basic	54.5	43.5	36.1
Weighted-average limited partner units outstanding diluted	54.5	43.6	36.1

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2012	2011	2010
		(Millions)	
Net income	$ 173.0	$ 139.6	$ 100.4
Other comprehensive income (loss):			
Reclassification of cash flow hedge losses into earnings	10.6	20.7	22.9
Net unrealized gains (losses) on cash flow hedges	0.1	(13.3)	(18.7)
Net unrealized losses on cash flow hedges predecessor operations	(0.6)	(1.8)	
Total other comprehensive income	10.1	5.6	4.2
Total comprehensive income	183.1	145.2	104.6
Total comprehensive income attributable to noncontrolling interests	(5.0)	(18.8)	(9.2)
Total comprehensive income attributable to partners	$ 178.1	$ 126.4	$ 95.4

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

		Partners Equity				
	Predecessor Equity	Common Unitholders	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
			(Millions)			
Balance, January 1, 2012	$ 257.4	$ 654.4	$ (4.7)	$ (21.2)	$ 212.4	$ 1,098.3
Net income	2.6	124.2	41.2		5.0	173.0
Other comprehensive income (loss)	(0.6)			10.7		10.1
Net change in advances to predecessor from DCP Midstream, LLC	(11.5)					(11.5)
Acquisition of additional 66.67% interest in Southeast Texas and NGL Hedge	(247.9)	39.5				(208.4)
Acquisition of additional 49.9% interest in East Texas					(175.8)	(175.8)
Issuance of units for Southeast Texas		48.0				48.0
Issuance of units for East Texas		33.0				33.0
Issuance of units for Mont Belvieu fractionators		60.0				60.0
Issuance of units for 33.33% interest in the Eagle Ford system		87.7				87.7
Deficit purchase price under carrying value of acquired net assets for Southeast Texas and East Texas		35.8		(4.2)		31.6
Excess purchase price over carrying value of acquired investments in Mont Belvieu fractionators		(174.8)				(174.8)
Excess purchase price over carrying value of acquired investment of 33.33% interest in the Eagle Ford system and NGL Hedge		(156.4)				(156.4)
Excess purchase price over carrying value of acquired net assets by unconsolidated affiliates for Goliad and NGL Hedge		(9.3)				(9.3)
Issuance of 11,285,956 common units		455.0				455.0
Equity-based compensation		(0.4)				(0.4)
Distributions to common unitholders and general partner		(144.5)	(36.8)			(181.3)
Distributions to noncontrolling interests					(6.2)	(6.2)
Contributions from DCP Midstream, LLC		10.6				10.6
Balance, December 31, 2012	$	$ 1,062.8	$ (0.3)	$ (14.7)	$ 35.4	$ 1,083.2

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (Continued)

	Partner s Equity					
	Predecessor Equity	Common Unitholders	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2010	$ 212.3	$ 415.5	$ (5.9)	$ (31.9)	$ 227.7	$ 817.7
Net income	43.2	32.2	15.8		9.2	100.4
Other comprehensive income				4.2		4.2
Net change in advances to predecessor from DCP Midstream, LLC	82.3					82.3
Purchase of additional interest in a subsidiary		1.0			(5.5)	(4.5)
Issuance of 5,870,200 common units		189.1				189.1
Equity based compensation		0.2				0.2
Distributions to common unitholders and general partner		(85.6)	(16.3)			(101.9)
Distributions to noncontrolling interests					(25.6)	(25.6)
Contributions from DCP Midstream, LLC		0.6				0.6
Contributions from noncontrolling interests					14.3	14.3
Excess purchase price over carrying value of acquired investment of 5% interest in Black Lake		(0.8)				(0.8)
Balance, December 31, 2010	$ 337.8	$ 552.2	$ (6.4)	$ (27.7)	$ 220.1	$ 1,076.0
Net income	20.4	75.2	25.2		18.8	139.6
Other comprehensive income (loss)	(1.8)			7.4		5.6
Net change in advances to predecessor from DCP Midstream, LLC	15.3					15.3
Acquisition of Southeast Texas	(114.3)					(114.3)
Excess purchase price over acquired assets		(34.8)		(0.9)		(35.7)
Issuance of 4,357,921 common units		169.9				169.9
Equity-based compensation		3.4				3.4
Distributions to DCP Midstream, LLC		(2.6)				(2.6)
Distributions to common unitholders and general partner		(108.9)	(23.5)			(132.4)
Distributions to noncontrolling interests					(44.8)	(44.8)
Contributions from noncontrolling interests					18.3	18.3
Balance, December 31, 2011	$ 257.4	$ 654.4	$ (4.7)	$ (21.2)	$ 212.4	$ 1,098.3

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2012	2011 (Millions)	2010
OPERATING ACTIVITIES:			
Net income	$ 173.0	$ 139.6	$ 100.4
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	63.4	100.6	88.1
Earnings from unconsolidated affiliates	(28.9)	(22.7)	(23.8)
Distributions from unconsolidated affiliates	29.3	25.3	30.0
Step acquisition equity interest re-measurement gain			(9.1)
Net unrealized (gains) losses on derivative instruments	(21.3)	(39.9)	8.4
Deferred income taxes, net		(29.2)	(0.1)
Other, net	2.8	4.2	(0.8)
Change in operating assets and liabilities which (used) provided cash, net of effects of acquisitions:			
Accounts receivable	29.9	31.5	(48.2)
Inventories	13.3	(14.3)	1.3
Accounts payable	(133.3)	63.5	9.9
Accrued interest	5.4		1.8
Other current assets and liabilities	(6.6)	5.6	3.0
Other long-term assets and liabilities	(2.1)	(3.4)	1.5
Net cash provided by operating activities	124.9	260.8	162.4
INVESTING ACTIVITIES:			
Capital expenditures	(200.4)	(165.7)	(75.9)
Acquisitions, net of cash acquired	(375.4)	(60.5)	(282.1)
Acquisition of unconsolidated affiliates and NGL Hedges	(312.0)	(114.3)	
Investments in unconsolidated affiliates	(184.0)	(7.0)	(2.3)
Return of investment from unconsolidated affiliates	1.0	1.6	1.2
Proceeds from sales of assets	0.3	5.2	3.5
Proceeds from sales of available-for-sale securities			10.1
Net cash used in investing activities	(1,070.5)	(340.7)	(345.5)
FINANCING ACTIVITIES:			
Proceeds from debt	2,664.8	1,524.0	868.2
Payments of debt	(1,791.5)	(1,425.0)	(833.4)
Payment of deferred financing costs	(7.7)	(4.2)	(2.1)
Proceeds from issuance of common units, net of offering costs	455.2	169.7	189.3
Excess purchase price over acquired unconsolidated affiliates and NGL Hedges	(192.8)	(35.7)	
Net change in advances to predecessor from DCP Midstream, LLC	(11.5)	10.9	82.3
Distributions to common unitholders and general partner	(181.3)	(132.4)	(101.9)
Distributions to noncontrolling interests	(6.2)	(44.8)	(25.6)
Contributions from noncontrolling interests			13.8
Contributions from DCP Midstream, LLC	10.3	18.3	0.6
Purchase of additional interest in a subsidiary			(3.5)
Net cash provided by financing activities	939.3	80.8	187.7

Net change in cash and cash equivalents	(6.3)	0.9	4.6
Cash and cash equivalents, beginning of year	7.6	6.7	2.1
Cash and cash equivalents, end of year	$ 1.3	$ 7.6	$ 6.7

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010

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, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs and condensate; and transporting, storing and selling propane in wholesale markets.

We are a Delaware limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our natural gas services segment (which includes our Northern Louisiana system; our Southern Oklahoma system; our 40% interest in Discovery Producer Services LLC, or Discovery; our Wyoming system; a 75% interest in Collbran Valley Gas Gathering, LLC, or Collbran or our Colorado system; our East Texas system (of which the remaining 49.9% was acquired in January 2012, and also includes the Crossroads system acquired in July 2012); our Michigan system; our Southeast Texas system (of which 33.33% and 66.67% were acquired in January 2011 and March 2012, respectively); our 33.33% interest in the Eagle Ford system (acquired in November 2012) and our wholly owned Eagle Plant, our NGL logistics segment (which includes the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, our 10% interest in the Texas Express intrastate NGL pipeline, the NGL storage facility in Michigan, the DJ Basin NGL fractionators and our minority ownership interests in the Mont Belvieu fractionators acquired in July 2012), and our wholesale propane logistics segment.

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, and 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 Phillips 66. 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 most of our assets. DCP Midstream, LLC owns approximately 28% of us.

The consolidated financial statements include the accounts of the Partnership and all majority-owned subsidiaries where we have the ability to exercise control. 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, are accounted for using the equity method. All intercompany balances and transactions have been eliminated.

Our predecessor operations consist of our initial 33.33% interest in Southeast Texas, which we acquired from DCP Midstream, LLC in January 2011, and the remaining 66.67% interest in Southeast Texas and commodity derivative hedge instruments related to the Southeast Texas storage business, which we acquired from DCP Midstream, LLC in March 2012. Prior to our acquisition of the remaining 66.67% interest in Southeast Texas, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method. Subsequent to this transaction, we own 100% of Southeast Texas which we account for as a consolidated subsidiary. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements include the historical results of our 100% interest in Southeast Texas and the natural gas commodity derivatives associated with the storage business for all periods presented. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC s basis in the net assets contributed. The amount of the purchase price in excess or in deficit of DCP Midstream, LLC s basis in the net assets is recognized as a reduction or an addition to partners equity. The financial statements of our predecessor 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 predecessor had been operated as an unaffiliated entity. In addition, the results of operations for acquisitions accounted for as business combinations have been included in the consolidated financial statements since their respective acquisition dates.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (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.

Inventories Inventories, which consist primarily of NGLs and natural gas, 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.

Goodwill and Intangible Assets Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We perform an annual impairment test of goodwill in the third quarter, and update the test during interim periods when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of a reporting unit. We primarily use a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and 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. For certain reporting units, we may elect to first assess qualitative factors to determine whether it is more likely than not that the fair value of our reporting units is less than the carrying value.

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. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

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.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

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.

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.

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.

Investments in Unconsolidated Affiliates 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 investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When there is evidence of loss in value, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates 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 considered to be permanently 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.

Noncontrolling Interest Noncontrolling interest represents any third party or affiliate interest in non-wholly-owned entities that we consolidate. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party or affiliate interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third party and affiliate investors.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

Accounting for Risk Management Activities and Financial Instruments Non-trading energy commodity derivatives are 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. The remaining non-trading derivatives, which are related to asset-based activities for which the normal purchase or normal sale exception is not elected, are recorded at fair value in the consolidated balance sheets as unrealized gains or unrealized losses in derivative instruments, with changes in the fair value recognized in the consolidated statements of operations. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

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

(a) Mark-to-market method 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 commodity derivative activity during the current period.

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

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

Cash Flow and Fair Value Hedges For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In 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 in accumulated other comprehensive income, or 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

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

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 relationships with quoted market prices and the expected relationship 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, compressing, treating, processing, transporting, storing and selling of natural gas, and producing, fractionating, transporting, storing and selling NGLs. Once natural gas is produced from wells, producers then seek to deliver the natural gas and its components to end-use markets. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees.

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, transporting or storing natural gas; and storing 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/liquids 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, NGLs and condensate 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, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas, NGLs and condensate, regardless of the actual amount of the

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

sales proceeds we receive. We keep the difference between the proceeds received and the amount remitted back to the producer. Under percent-of-liquids arrangements, we do not keep any amounts related to residue natural gas proceeds and only keep amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. 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. Additionally, these arrangements may include fee-based components. Our revenues under percent-of-proceeds arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly with the price of NGLs and condensate.

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

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

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

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

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody to the product, and incur the risks and rewards of ownership. We recognize revenues for non-trading 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 accounts receivable or accounts payable 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.

Significant Customers There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2012, 2011 and 2010. There was one third party customer that accounted for approximately 20% of revenues of the Wholesale Propane Logistics segment for the year ended December 31, 2012, and approximately 17% of total operating revenues for the years ended

December 31, 2011 and 2010, respectively. We also had significant transactions with affiliates.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

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, 2012 and 2011, included in the consolidated balance sheets as other current liabilities amounted to $0.8 million and $0.8 million, respectively, and as other long-term liabilities amounted to $1.0 million and $1.2 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.

Allowance for Doubtful Accounts Management estimates the amount of required allowances for the potential non-collectability of accounts receivable generally based upon the number of days past due, past collection experience and consideration of other relevant factors. However, past experience may not be indicative of future collections and therefore additional charges could be incurred in the future to reflect differences between estimated and actual collections.

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 proportionately included in the federal returns of each partner.

Net Income or Loss per Limited Partner Unit Basic and diluted net income or loss per limited partner unit, or LPU, is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the period. Diluted net income or loss per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method.

Capitalized Interest We capitalize interest during construction on major projects. Interest is calculated on the monthly outstanding capital balance and ceases in the month that the asset is placed into service. We also capitalize interest on our equity method investments which are devoting substantially all efforts to establishing a new business and have not yet begun planned principal operations. Capitalization ceases when the investee commences planned principal operations. The rates used to calculate capitalized interest are the weighted-average cost of debt, including the impact of interest rate swaps.

3. Acquisitions

On November 2, 2012, we acquired a 33.33% interest in DCP SC Texas GP, or the Eagle Ford system, from DCP Midstream, LLC and a $43.2 million fixed price commodity derivative hedge (also referred to as the NGL Hedge) for a three-year period for aggregate consideration of $438.3 million, less customary working capital and other purchase price adjustments of $7.1 million. $343.5 million of the consideration was financed with a 2-year Term Loan Agreement and $87.7 million was financed by the issuance at closing of an aggregate 1,912,663 of our common units to DCP Midstream, LLC. The $156.4 million excess purchase price over the

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

carrying value of the acquired investment was recorded as a decrease in common unitholders equity. The Eagle Ford system acquisition represents a transaction between entities under common control, but does not represent a change in reporting entity. Accordingly, we have included the results of our 33.33% interest in the Eagle Ford system prospectively from the date of acquisition. Our interest in the Eagle Ford system is accounted for as an unconsolidated affiliate using the equity method and is included in our Natural Gas Services segment. On December 5, 2012, DCP SC Texas GP announced the construction of the Goliad Plant, a cryogenic plant that will serve the Eagle Ford shale. The Goliad plant will have gas processing capacity of 200 MMcf/d and will be part of the Eagle Ford system. The Goliad plant will be constructed and funded by the Eagle Ford system. We contributed $19.1 million to the Eagle Ford system for our 33.33% interest in the project, which included working capital and construction work in process, plus an incremental payment of $16.7 million. DCP Midstream, LLC also provided a $7.3 million two-year direct commodity price hedge (also referred to as the NGL Hedge) for our 33.33% interest in the project. The excess purchase price over the carrying value of the acquired net assets by the Eagle Ford system of $9.3 million was recorded as a decrease in common unitholders equity. Our total investment will be approximately $97.0 million, which includes the new Goliad Plant, a gathering system feeding the plant and ancillary support facilities including compression, liquids handling and residue pipeline interconnect facilities. The Goliad plant is expected to be completed in the first quarter of 2014.

On July 3, 2012, we acquired the Crossroads processing plant and associated gathering system from Penn Virginia Resource Partners, L.P. for $63.0 million. The acquisition was financed at closing with borrowings under our revolving credit facility. The Crossroads system, located in the southeastern portion of Harrison County in East Texas, includes approximately 8 miles of gas gathering pipeline, an 80 MMcf/d cryogenic processing plant, approximately 20 miles of NGL pipeline and a 50% ownership interest in an approximately 11-mile residue gas pipeline, or CrossPoint Pipeline, LLC, which we have accounted for as an unconsolidated affiliate using the equity method. The Crossroads system is a part of our East Texas system, which is included in our Natural Gas Services segment.

We have accounted for the Crossroads business combination based on estimates of the fair value of assets acquired and liabilities assumed, including: property, plant and equipment; the equity investment in CrossPoint Pipeline, LLC; a liability for a firm transportation agreement which expires in 2015; and a gas purchase agreement under which a portion of those firm transportation payments are recoverable. Expected cash payments and receipts have been recorded at their estimated fair value and are included in other current liabilities, other long-term liabilities, and accounts receivable as of the acquisition date. The preliminary estimates of the fair value of identifiable assets acquired and liabilities assumed are subject to revisions, which may result in adjustments to the preliminary values as additional information relative to the fair value of assets and liabilities becomes available. The values assigned to the assets acquired and liabilities assumed may change in subsequent financial statements pending the final estimates of fair value. The following table summarizes the aggregate consideration and fair value of the identifiable assets acquired and liabilities assumed in the acquisition of Crossroads as of the acquisition date:

	July 3, 2012 (Millions)
Aggregate consideration	$ 63.0
Accounts receivable	$ 4.2
Property, plant and equipment	63.1
Investments in unconsolidated affiliates	6.1
Other current liabilities	(4.1)
Other long-term liabilities	(6.3)
Total	$ 63.0

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

The results of operations for acquisitions accounted for as a business combination are included in our results subsequent to the date of acquisition. Accordingly, total operating revenues of $21.5 million and net income of $1.2 million associated with Crossroads from the acquisition date to December 31, 2012 are included in our consolidated statement of operations.

Supplemental pro forma information is presented for comparative periods prior to the date of acquisition; however, comparative periods in the consolidated financial statements are not adjusted to include the results of the acquisition. The following tables present unaudited supplemental pro forma information for the consolidated statement of operations for the years ended December 31, 2012 and 2011, as if the acquisition of Crossroads had occurred at the beginning of the earliest period presented.

	Year Ended December 31, 2012		
	DCP Midstream Partners, LP	Acquisition of Crossroads (a)	DCP Midstream Partners, LP Pro Forma
		(Millions)	
Total operating revenues	$ 1,720.7	$ 27.0	$ 1,747.7
Net income attributable to partners	$ 168.0	$ 1.6	$ 169.6
Less:			
Net income attributable to predecessor operations	(2.6)		(2.6)
General partner s interest in net income	(41.2)		(41.2)
Net income allocable to limited partners	$ 124.2	$ 1.6	$ 125.8
Net income per limited partner unit basic and diluted	$ 2.28	$ 0.03	$ 2.31

(a) The year ended December 31, 2012 includes the financial results of Crossroads for the period from January 1, 2012 through July 2, 2012.

	Year Ended December 31, 2011		
	DCP Midstream Partners, LP	Acquisition of Crossroads	DCP Midstream Partners, LP Pro Forma
		(Millions)	
Total operating revenues	$ 2,358.4	$ 114.3	$ 2,472.7
Net income attributable to partners	$ 120.8	$ 4.0	$ 124.8
Less:			
Net income attributable to predecessor operations	(20.4)		(20.4)
General partner s interest in net income	(25.2)		(25.2)
Net income allocable to limited partners	$ 75.2	$ 4.0	$ 79.2
Net income per limited partner unit basic	$ 1.73	$ 0.09	$ 1.82

Net income per limited partner unit diluted	$ 1.72	$ 0.09	$ 1.81

The supplemental pro forma total operating revenues for the year ended December 31, 2012 was adjusted to eliminate $5.4 million related to a contractual gas processing arrangement between us and Crossroads during the period.

The supplemental pro forma information is not intended to reflect actual results that would have occurred if the acquired business 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.

On July 2, 2012, we acquired the minority ownership interests in two non-operated Mont Belvieu fractionators, or the Mont Belvieu fractionators, from DCP Midstream, LLC for aggregate consideration of

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

$200.0 million, plus $4.6 million in working capital and other customary purchase price adjustments. $60.0 million of the aggregate consideration was financed by the issuance at closing of 1,536,098 of our common units to DCP Midstream, LLC. We entered into a 2-year Term Loan Agreement to fund the remaining $140.0 million. The $174.8 million excess purchase price over the carrying value of the acquired investments was recorded as a decrease in common unitholders equity. The minority ownership interests include a 12.5% interest in the Enterprise fractionator, which is operated by Enterprise Products Partners L.P., and a 20% interest in the Mont Belvieu 1 fractionator, which is operated by ONEOK Partners. We have accounted for the results of the minority ownership interests in the Mont Belvieu fractionators prospectively from the date of acquisition. The Mont Belvieu fractionators are accounted for as unconsolidated affiliates using the equity method and are included in our NGL Logistics segment.

On April 12, 2012, we acquired a 10% ownership interest in the Texas Express Pipeline joint venture from the operator, Enterprise Products Partners, L.P., or Enterprise, representing an approximate investment of $85.0 million in the joint venture. At closing, we paid $10.9 million for our 10% ownership interest in the Texas Express Pipeline joint venture, representing our proportionate share of the investment through the closing date, and will be responsible for spending an approximate $75.0 million for our share of the remaining construction costs of the pipeline. Originating near Skellytown in Carson County, Texas, the 20-inch diameter Texas Express Pipeline will extend approximately 580 miles to Enterprise s natural gas liquids fractionation and storage complex at Mont Belvieu, Texas, and will provide access to other third party facilities in the area. The Texas Express Pipeline will have an initial capacity of approximately 280 MBbls/d and as of December 31, 2012, has in place long-term, fee-based, ship-or-pay transportation commitments of 252 MBbls/d, including a commitment from DCP Midstream, LLC of 20 MBbls/d. The pipeline is expected to be completed in mid-2013.

On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas and commodity derivative hedge instruments (also referred to as the NGL Hedge) related to the Southeast Texas storage business for consideration of $240.0 million, subject to working capital and other customary purchase price adjustments. $192.0 million of the consideration was financed with a portion of the net proceeds from our 4.95% 10-year Senior Notes offering. The remaining $48.0 million consideration was financed by the issuance at closing of an aggregate of 1,000,417 of our common units to DCP Midstream, LLC. DCP Midstream, LLC also provided fixed price NGL commodity derivatives, valued at $39.5 million, for the three year period subsequent to closing the newly acquired interest. The $8.9 million deficit purchase price under the carrying value of the acquired net assets and the $48.0 million of common units issued as consideration for this acquisition were recorded as an increase in common unitholders equity. Prior to the acquisition of the additional interest in Southeast Texas, we owned a 33.33% interest which we accounted for as an unconsolidated affiliate using the equity method. Certain of the NGL commodity derivatives were valued at $24.6 million and represent consideration for the termination of a fee-based storage arrangement we had with DCP Midstream, LLC in conjunction with our initial 33.33% interest in Southeast Texas; the remaining portion of the commodity derivatives, valued at $14.9 million, mitigate a portion of our currently anticipated commodity price risk associated with the gathering and processing portion of the 66.67% interest in Southeast Texas acquired on March 30, 2012. The acquisition of the remaining 66.67% interest in Southeast Texas represents a transaction between entities under common control and a change in reporting entity. Accordingly, our consolidated financial statements have been adjusted to retrospectively include the historical results of our 100% interest in Southeast Texas and the commodity derivative hedge instruments associated with the storage business for all periods presented, similar to the pooling method.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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Combined Financial Information

The results of our 100% interest in Southeast Texas are included in the consolidated balance sheets as of December 31, 2012 and 2011. The following table presents the previously reported December 31, 2011 consolidated balance sheet, adjusted for the acquisition of the remaining 66.67% interest in Southeast Texas from DCP Midstream, LLC:

As of December 31, 2011

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate Southeast Texas (b)	Remove Southeast Texas Investment in Unconsolidated Affiliate (c)	Consolidated DCP Midstream Partners, LP (As currently reported)
			(Millions)	
ASSETS				
Current assets:				
Cash and cash equivalents	$ 6.7	$ 0.9	$	$ 7.6
Accounts receivable	161.4	53.4		214.8
Inventories	64.7	23.2		87.9
Other	7.1	36.3		43.4
Total current assets	239.9	113.8		353.7
Property, plant and equipment, net	1,181.8	317.6		1,499.4
Goodwill and intangible assets, net	255.8	43.3		299.1
Investments in unconsolidated affiliates	208.7		(101.6)	107.1
Other non-current assets	17.4	0.7		18.1
Total assets	$ 1,903.6	$ 475.4	$ (101.6)	$ 2,277.4
LIABILITIES AND EQUITY				
Accounts payable and other current liabilities	$ 269.2	$ 111.3	$	$ 380.5
Long-term debt	746.8			746.8
Other long-term liabilities	46.7	5.1		51.8
Total liabilities	1,062.7	116.4		1,179.1
Commitments and contingent liabilities				
Equity:				
Partners equity				
Net equity	649.7	360.8	(103.4)	907.1
Accumulated other comprehensive loss	(21.2)	(1.8)	1.8	(21.2)
Total partners equity	628.5	359.0	(101.6)	885.9
Noncontrolling interests	212.4			212.4

Total equity	840.9	359.0	(101.6)	1,098.3
Total liabilities and equity	$ 1,903.6	$ 475.4	$ (101.6)	$ 2,277.4

(a) Amounts as previously reported with 33.33% of Southeast Texas results presented as investments in unconsolidated affiliates.

(b) Adjustments to present Southeast Texas on a consolidated basis at 100% ownership, including commodity derivatives.

(c) Adjustments to remove Southeast Texas 33.33% investment in unconsolidated affiliates.

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DCP MIDSTREAM PARTNERS, LP

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

The results of our 100% interest in Southeast Texas are included in the consolidated statements of operations for the years ended December 31, 2012, 2011 and 2010. The following tables present the previously reported consolidated statements of operations for the years ended December 31, 2011 and 2010, adjusted for the acquisition of the remaining 66.67% interest in Southeast Texas from DCP Midstream, LLC:

Year Ended December 31, 2011

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate Southeast Texas (b) (Millions)	Remove Southeast Texas Equity Earnings (c)	Consolidated DCP Midstream Partners, LP (As currently reported)
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 1,413.3	$ 765.2	$	$ 2,178.5
Transportation, processing and other	163.2	9.0		172.2
(Losses) gains from commodity derivative activity, net	(6.7)	14.4		7.7
Total operating revenues	1,569.8	788.6		2,358.4
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	1,229.8	703.2		1,933.0
Operating and maintenance expense	105.4	20.3		125.7
Depreciation and amortization expense	81.0	19.6		100.6
General and administrative expense	37.3	11.0		48.3
Other income	(0.5)			(0.5)
Total operating costs and expenses	1,453.0	754.1		2,207.1
Operating income	116.8	34.5		151.3
Interest expense, net	(33.9)			(33.9)
Earnings from unconsolidated affiliates	36.9		(14.2)	22.7
Income before income taxes	119.8	34.5	(14.2)	140.1
Income tax (expense) benefit	(0.6)	0.1		(0.5)
Net income	119.2	34.6	(14.2)	139.6
Net income attributable to noncontrolling interests	(18.8)			(18.8)
Net income attributable to partners	$ 100.4	$ 34.6	$ (14.2)	$ 120.8

(a) Amounts as previously reported with 33.33% of Southeast Texas results presented as earnings from unconsolidated affiliates.

(b) Adjustments to present Southeast Texas on a consolidated basis at 100% ownership, including commodity derivatives.

(c) Adjustments to remove Southeast Texas equity earnings at 33.33%.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

Year Ended December 31, 2010

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate Southeast Texas (b) (Millions)	Remove Southeast Texas Equity Earnings (c)	Consolidated DCP Midstream Partners, LP (As currently reported)
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 1,162.7	$ 812.4	$	$ 1,975.1
Transportation, processing and other	115.3	15.0		130.3
(Losses) gains from commodity derivative activity, net	(8.5)	11.5		3.0
Total operating revenues	1,269.5	838.9		2,108.4
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	1,032.6	750.5		1,783.1
Operating and maintenance expense	79.8	18.5		98.3
Depreciation and amortization expense	73.7	14.4		88.1
General and administrative expense	33.7	12.1		45.8
Gain on step acquisition	(9.1)			(9.1)
Other income	(4.0)	(1.0)		(5.0)
Total operating costs and expenses	1,206.7	794.5		2,001.2
Operating income	62.8	44.4		107.2
Interest expense, net	(29.1)			(29.1)
Earnings from unconsolidated affiliates	38.2		(14.4)	23.8
Income before income taxes	71.9	44.4	(14.4)	101.9
Income tax expense	(0.3)	(1.2)		(1.5)
Net income	71.6	43.2	(14.4)	100.4
Net income attributable to noncontrolling interests	(9.2)			(9.2)
Net income attributable to partners	$ 62.4	$ 43.2	$ (14.4)	$ 91.2

(a) Amounts as previously reported with 33.33% of Southeast Texas results presented as earnings from unconsolidated affiliates.

(b) Adjustments to present Southeast Texas on a consolidated basis at 100% ownership, including commodity derivatives.

(c) Adjustments to remove Southeast Texas equity earnings at 33.33%.
The currently reported results are not intended to reflect actual results that would have occurred if the acquired business had been combined during the period presented, nor is it intended to be indicative of the results of operations that may be achieved by us in the future.

On January 3, 2012, we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC for consideration of $165.0 million, subject to working capital and other customary purchase price adjustments. $132.0 million of the consideration was financed with proceeds from a 2-year Term Loan Agreement. The remaining $33.0 million consideration was financed by the issuance at closing of an aggregate of 727,520 of our common units to DCP Midstream, LLC. The $22.7 million deficit purchase price under the carrying value of the acquired net assets and the $33.0 million of common units issued as consideration for this acquisition

DCP MIDSTREAM PARTNERS, LP

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

were recorded as an increase in common unitholders equity. Prior to the contribution of the additional interest in East Texas, we owned a 50.1% interest which we accounted for as a consolidated subsidiary. The contribution of the remaining 49.9% interest in East Texas represents a transaction between entities under common control, but does not represent a change in reporting entity. Accordingly, we have included the results of the remaining 49.9% interest in East Texas prospectively from the date of contribution.

4. Agreements and Transactions with Affiliates
DCP Midstream, LLC

Omnibus Agreement and Other General and Administrative Charges

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC.

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

	Year Ended December 31,		
	2012	2011	2010
		(Millions)	
Omnibus Agreement	$ 25.4	$ 10.2	$ 9.9
Other fees DCP Midstream, LLC	3.9	18.9	21.4
Total DCP Midstream, LLC	$ 29.3	$ 29.1	$ 31.3

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. 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.

On January 3, 2012, we extended the omnibus agreement through December 31, 2012 for an annual fee of $17.6 million, with the primary increase resulting from the acquisition of the remaining 49.9% interest in East Texas. On March 30, 2012, in conjunction with our acquisition of the remaining 66.67% interest in Southeast Texas, we increased the annual fee we pay to DCP Midstream, LLC under the agreement by $10.3 million, prorated for the remainder of the 2012 calendar year. These fees were previously allocated to East Texas and Southeast Texas. In July 2012, in conjunction with our acquisition of the minority ownership interests in the Mont Belvieu fractionators, we increased the annual fee we pay to DCP Midstream, LLC by $0.2 million, prorated for the remainder of the 2012 calendar year. As a result of these transactions, the annual fee payable in future years to DCP Midstream, LLC will be $28.1 million. 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 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; and

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.

DCP MIDSTREAM PARTNERS, LP

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Before the addition of East Texas and Southeast Texas to the Omnibus Agreement, East Texas and Southeast Texas incurred general and administrative expenses directly from DCP Midstream, LLC. During the years ended December 31, 2011 and 2010, East Texas incurred $7.5 million and $7.8 million, respectively, and during the years ended December 31, 2012, 2011 and 2010, Southeast Texas incurred $2.5 million, $10.0 million and $12.1 million, respectively, which includes expenses for our predecessor operations. General and administrative expenses incurred by East Texas and Southeast Texas effective January 3, 2012 and March 30, 2012, respectively, are covered by the Omnibus Agreement.

In addition to the Omnibus Agreement and amounts incurred by East Texas and Southeast Texas, we incurred other fees with DCP Midstream, LLC, which includes expenses for our predecessor operations, of $1.4 million, $1.4 million and $1.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. These amounts include allocated expenses, including professional services, insurance, internal audit and various other corporate functions.

On February 14, 2013, we entered into a Services Agreement with DCP Midstream, LLC, which replaces the Omnibus Agreement, whereby DCP Midstream, LLC will continue to provide us with general and administrative services previously provided under the Omnibus Agreement. The annual fee payable in future years to DCP Midstream, LLC under the Services Agreement will be consistent with the fee structure previously payable under the Omnibus Agreement, and will be $28.6 million for 2013. Pursuant to the Services Agreement, we will reimburse DCP Midstream, LLC for expenses and expenditures incurred or payments made on our behalf.

Competition

None of DCP Midstream, LLC, or any of its affiliates, including Spectra Energy and Phillips 66, 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 Phillips 66, 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.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC was a significant customer during the years ended December 31, 2012, 2011 and 2010. We sell a portion of our residue gas, NGLs and condensate to, purchase natural gas and other petroleum products from, and provide gathering and transportation services for, DCP Midstream, LLC. We anticipate continuing to purchase from and sell commodities and services to DCP Midstream, LLC in the ordinary course of business. In addition, DCP Midstream, LLC conducts derivative activities on our behalf. We have and may continue to enter into derivative transactions directly with DCP Midstream, LLC, whereby DCP Midstream, LLC is the counterparty.

We have a contractual arrangement with DCP Midstream, LLC, through March 2022, in which we pay DCP Midstream, LLC a fee for processing services associated with the gas we gather on our Southern Oklahoma system, which is part of our Natural Gas Services segment. In addition, in February 2010, a contract was signed with DCP Midstream, LLC providing for adjustments to those fees based upon plant efficiencies related to our portion of volumes from the Southern Oklahoma system being processed at DCP Midstream, LLC s plant through March 2022. We generally report fees associated with these activities in the consolidated statements of operations as purchases of natural gas, propane, NGLs and condensate from affiliates. In addition, as part of this arrangement, DCP Midstream, LLC pays us a fee for certain gathering services. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system, included in our Northern Louisiana system, which is part of our Natural Gas Services segment,

DCP MIDSTREAM PARTNERS, LP

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

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 us and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. We purchase natural gas from DCP Midstream, LLC upstream of Pelico and transport it to Pelico under an interruptible transportation agreement with an affiliate. Our purchases from DCP Midstream, LLC are at DCP Midstream, LLC s actual acquisition cost plus any transportation service charges. Volumes that exceed our on-system demand are sold to DCP Midstream, LLC at an index-based price, less contractually agreed to marketing fees. Revenues associated with these activities are reported gross in our consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates.

In our Natural Gas Services segment, we sell NGLs processed at certain of our plants, and sell condensate removed from the gas gathering systems that deliver to certain of our systems under contracts 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.

As a result of a downstream outage, certain of our assets were required to curtail NGL production during 2012. DCP Midstream, LLC has reimbursed us for the impact of the curtailment and accordingly, we have recorded $2.5 million to sales of natural gas, propane, NGLs and condensate to affiliates and $0.2 million to transportation, processing and other to affiliates in the consolidated statements of operations for the year ended December 31, 2012.

In conjunction with our acquisitions of our East Texas and Southeast Texas systems, which are part of our Natural Gas Services segment, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on East Texas and Southeast Texas capital projects. These reimbursements are for specific capital projects which have commenced within three years from the respective acquisition dates. DCP Midstream, LLC made capital contributions to East Texas for capital projects of $5.3 million, $18.3 million and $13.8 million for the years ended December 31, 2012, 2011 and 2010, respectively. DCP Midstream, LLC made capital contributions to Southeast Texas for capital projects of $4.9 million for the year ended December 31, 2012.

During the year ended December 31, 2011, East Texas received $7.8 million in business interruption recoveries related to the first quarter 2009 fire that was caused by a third party underground pipeline rupture outside of our property, or the East Texas recovery settlement. We have allocated the recoveries based upon relative ownership percentages at the time the losses were incurred, factoring in amounts previously reimbursed to us by DCP Midstream, LLC. For the year ended December 31, 2011, we recorded $6.6 million to our consolidated statement of operations in sales of natural gas, propane, NGLs and condensate , with $4.6 million representing DCP Midstream, LLC s portion in net income attributable to noncontrolling interests.

On September 16, 2010, we entered into an agreement with DCP Midstream, LLC to sell certain surplus equipment at Collbran, part of our Natural Gas Services segment, with a net book value of $6.2 million for net proceeds of $3.6 million. The surplus equipment is the result of a consolidation of operations at our Anderson Gulch plant in the Piceance Basin. The net proceeds of $3.6 million were distributed 75% to us and 25% to the noncontrolling interest in Collbran, based upon proportionate ownership, during the year ended December 31, 2010. The sale was completed when title to the surplus equipment passed to DCP Midstream, LLC in March 2011. We have recognized a distribution of $2.6 million for year ended December 31, 2011 to DCP Midstream, LLC in our consolidated statements of changes in equity representing the difference between the net book value and the proceeds received for the surplus equipment.

In our NGL Logistics segment, 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 and Wilbreeze pipelines, pursuant to fee-based rates that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on these pipelines under the transportation agreements. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

DCP MIDSTREAM PARTNERS, LP

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

With respect to our Wattenberg pipeline, effective January 1, 2011, we entered into a 10-year dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC s processing facilities are dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenues under our tariff. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

We pay a fee to DCP Midstream, LLC to operate our DJ Basin NGL fractionators and receive fees for the processing of DCP Midstream, LLC s committed NGLs produced by them in Colorado at our DJ Basin NGL fractionators under agreements that are effective through March 2018. We incurred fees of $0.6 million during each of the years ended December 31, 2012 and 2011, which are included in operating and maintenance expense in the consolidated statements of operations.

DCP Midstream, LLC has issued parental guarantees, totaling $25.0 million as of December 31, 2012, in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We pay DCP Midstream, LLC a fee of 0.5% per annum on these outstanding guarantees.

Spectra Energy

We had propane supply agreements with Spectra Energy that expired in April 2012, which provided us propane supply at our marine terminals, included in our Wholesale Propane Logistics segment, for up to approximately 185 million gallons of propane annually.

ConocoPhillips and Phillips 66

Prior to May 2012, DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, was owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. In May 2012, ConocoPhillips separated its business into two stand-alone publicly traded companies. As a result of this transaction, DCP Midstream, LLC is no longer owned 50% by ConocoPhillips. ConocoPhillips 50% ownership interest in DCP Midstream, LLC has been transferred to the new downstream company, Phillips 66.

We have multiple agreements with Phillips 66 and its affiliates, and anticipate continuing to sell to Phillips 66 and its affiliates in the ordinary course of business. Prior to ConocoPhillips separation in May 2012, these agreements were with ConocoPhillips. We continue to have agreements with ConocoPhillips, including fee-based and percent-of-proceeds gathering and processing arrangements, and gas purchase and gas sales agreements; however, we do not consider ConocoPhillips to be a related party effective May 1, 2012.

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DCP MIDSTREAM PARTNERS, LP

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

Summary of Transactions with Affiliates

The following table summarizes the transactions with affiliates:

	Year Ended December 31, 2012	2011	2010
		(Millions)	
DCP Midstream, LLC:			
Sales of natural gas, propane, NGLs and condensate	$ 721.4	$ 1,058.7	$ 881.2
Transportation, processing and other	$ 35.5	$ 26.0	$ 12.1
Purchases of natural gas, propane and NGLs	$ 134.4	$ 185.8	$ 183.9
Gains (losses) from commodity derivative activity, net	$ 52.6	$ 0.2	$ (1.9)
Operating and maintenance expense	$ 0.6	$ 0.6	$
General and administrative expense	$ 29.3	$ 29.1	$ 31.3
Interest expense	$ 0.3	$ 0.4	$ 0.2
Spectra Energy:			
Transportation, processing and other	$ 0.1	$	$ 0.2
Purchases of natural gas, propane and NGLs (a)	$ 113.1	$ 249.6	$ 82.1
Operating and maintenance expense	$ 0.1	$	$ (0.3)
Other income	$	$	$ 3.0
ConocoPhillips (b):			
Sales of natural gas, propane, NGLs and condensate	$ 9.0	$ 52.2	$ 43.0
Transportation, processing and other	$ 2.3	$ 7.4	$ 9.9
Purchases of natural gas, propane and NGLs	$ 1.3	$ 5.8	$ 7.4
General and administrative expense	$ 0.1	$ 0.3	$ 0.2
(Losses) gains from commodity derivative activity, net	$	$	$ (0.4)
Phillips 66 (b):			
Sales of natural gas, propane, NGLs and condensate	$ 0.5	$	$
General and administrative expense	$ 0.2	$	$
Unconsolidated affiliates:			
Purchases of natural gas, propane and NGLs	$ 2.4	$ 6.0	$ 4.8

(a) Includes a $17.0 million payment received in December 2010 for reimbursement of damages we incurred when an international propane supplier breached its contract with Spectra Energy.

(b) In connection with the Phillips 66 separation, ConocoPhillips is not considered to be a related party for periods after April 30, 2012 and Phillips 66 is considered a related party for periods starting May 1, 2012.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

We had balances with affiliates as follows:

	December 31, 2012	December 31, 2011
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 86.1	$ 100.0
Accounts payable	$ 33.1	$ 22.6
Unrealized gains on derivative instruments current	$ 47.9	$ 0.6
Unrealized gains on derivative instruments long term	$ 64.4	$
Unrealized losses on derivative instruments current	$ (10.5)	$ (0.6)
Unrealized losses on derivative instruments long term	$	$ (2.6)
Spectra Energy:		
Accounts receivable	$ 0.1	$ 0.1
Accounts payable	$	$ 21.4
ConocoPhillips (a):		
Accounts receivable	$	$ 6.1
Accounts payable	$	$ 0.4
Unrealized gains on derivative instruments current	$	$ 2.5
Unrealized losses on derivative instruments current	$	$ (2.0)
Phillips 66 (a):		
Accounts receivable	$ 0.1	$
Unconsolidated affiliates:		
Accounts payable	$ 0.6	$ 2.4

(a) In connection with the Phillips 66 separation, ConocoPhillips is not considered to be a related party for periods after April 30, 2012 and Phillips 66 is considered a related party for periods starting May 1, 2012.

5. Inventories

Inventories were as follows:

	December 31, 2012	December 31, 2011
	(Millions)	
Natural gas	$ 22.1	$ 25.6
NGLs	52.6	62.3
Total inventories	$ 74.7	$ 87.9

We recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their estimated market value. These non-cash charges are a component of purchases of natural gas, propane and NGLs in the consolidated statements of operations. We recognized $19.3 million and $6.4 million in lower of cost or market adjustments during the year ended December 31, 2012 and 2011, respectively.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010 (Continued)

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	Depreciable Life	December 31, 2012	December 31, 2011
		(Millions)	
Gathering and transmission systems	20 50 Years	$ 1,325.1	$ 1,211.9
Processing, storage, and terminal facilities	35 60 Years	822.6	742.8
Other	3 30 Years	26.4	23.1
Construction work in progress		305.0	218.3
Property, plant and equipment		2,479.1	2,196.1
Accumulated depreciation		(751.7)	(696.7)
Property, plant and equipment, net		$ 1,727.4	$ 1,499.4

Interest capitalized on construction projects in 2012, 2011 and 2010, was $7.2 million, $1.6 million and $0.2 million, respectively.

We revised the depreciable lives for our gathering and transmission systems, processing, storage and terminal facilities, and other assets effective April 1, 2012. The key contributing factors to the change in depreciable lives is an increase in the estimated remaining economically recoverable reserves resulting from the development of techniques that improve commodity production in the regions our assets serve. Advances in extraction processes, along with better technology used to locate commodity reserves, is giving producers greater access to unconventional commodities. Based on our property, plant and equipment as of April 1, 2012, the new remaining depreciable lives resulted in an approximate $35.7 million reduction in depreciation expense for the year ended December 31, 2012. This change in our estimated depreciable lives increased net income per limited partner unit by $0.66 for the year ended December 31, 2012.

In connection with our evaluation of useful lives, we corrected the classification for certain assets within the presentation of our major classes of property, plant and equipment as of December 31, 2011.

Depreciation expense was $55.0 million, $92.2 million and $83.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Asset Retirement Obligations As of December 31, 2012 and 2011, we had asset retirement obligations of $16.9 million and $12.4 million, respectively, included in other long-term liabilities in the consolidated balance sheets. During the first quarter of 2012, we recorded a change in estimate to increase our asset retirement obligations by approximately $4.3 million. The change in estimate was primarily attributable to a reassessment of anticipated timing of settlements and of the original asset retirement obligation estimated amounts. Accretion expense for the years ended December 31, 2012, 2011 and 2010 was $0.1 million, $0.7 million and $0.7 million, respectively.

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, 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.

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

7. Goodwill and Intangible Assets

The carrying amount of goodwill is as follows:

	December 31, 2012	December 31, 2011
	(Millions)	
Beginning of period	$ 153.8	$ 151.2
Acquisitions		2.6
End of period	$ 153.8	$ 153.8

The carrying value of goodwill as of December 31, 2012 and 2011 was $82.2 million for each of the years for our Natural Gas Services segment, $34.7 million for each of the years for our NGL Logistics segment, and $36.9 million for each of the years for our Wholesale Propane Logistics segment.

We performed our annual goodwill assessment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. As a result of our assessment, we concluded that the entire amount of goodwill disclosed on the condensed consolidated balance sheet is recoverable. We used a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and 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. 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 goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

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, 2012	December 31, 2011
	(Millions)	
Gross carrying amount	$ 164.3	$ 164.3
Accumulated amortization	(27.4)	(19.0)
Intangible assets, net	$ 136.9	$ 145.3

For the years December 31, 2012, 2011 and 2010, we recorded amortization expense of $8.4 million, $8.4 million and $4.9 million, respectively. As of December 31, 2012, the remaining amortization periods ranged from approximately 9 years to 23 years, with a weighted-average remaining period of approximately 18 years.

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (Millions)
2013	$ 8.4
2014	8.4
2015	8.4
2016	8.4
2017	8.4
Thereafter	94.9
Total	$ 136.9

8. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

		Carrying Value as of	
	Percentage Ownership	December 31, 2012	December 31, 2011
		(Millions)	
Eagle Ford System	33.33%	$ 255.2	$
Discovery Producer Services LLC	40%	222.9	106.9
Texas Express Pipeline	10%	40.8	
Mont Belvieu Enterprise Fractionator	12.5%	18.5	
Mont Belvieu 1 Fractionator	20%	14.3	
CrossPoint Pipeline, LLC	50%	6.2	
Other	50%	0.1	0.2
Total investments in unconsolidated affiliates		$ 558.0	$ 107.1

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $30.2 million and $32.6 million at December 31, 2012 and 2011, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu 1 of $5.5 million at December 31, 2012, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Mont Belvieu 1.

Earnings from investments in unconsolidated affiliates were as follows:

	Year Ended December 31,		
	2012	2011	2010
		(Millions)	
Eagle Ford System	$ 2.8	$	$
Discovery Producer Services LLC	14.6	22.7	23.0
Mont Belvieu Enterprise Fractionator	5.3		
Mont Belvieu 1 Fractionator	6.0		
CrossPoint Pipeline, LLC	0.2		
Other (a)			0.8
Total earnings from unconsolidated affiliates	$ 28.9	$ 22.7	$ 23.8

DCP MIDSTREAM PARTNERS, LP

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(a) On July 27, 2010, we acquired an additional 5% interest in Black Lake from DCP Midstream, LLC in a transaction among entities under common control, and on July 30, 2010, we acquired an additional 50% interest in Black Lake from an affiliate of BP PLC, bringing our ownership interest in Black Lake to 100%. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary and accordingly, earnings from unconsolidated affiliates excludes the results of Black Lake since July 30, 2010.

The following summarizes combined financial information of our investments in unconsolidated affiliates:

	Year Ended December 31,		
	2012	2011	2010 (a)
		(Millions)	
Statements of operations:			
Operating revenue	$ 394.4	$ 210.7	$ 211.6
Operating expenses	$ 284.1	$ 159.9	$ 156.7
Net income	$ 110.0	$ 50.8	$ 52.7

(a) The combined financial information includes the results of Black Lake through July 30, 2010.

	December 31,	
	2012	2011
	(Millions)	
Balance sheet:		
Current assets	$ 187.1	$ 38.1
Long-term assets	2,111.2	359.9
Current liabilities	(185.8)	(20.4)
Long-term liabilities	(51.6)	(28.5)
Net assets	$ 2,060.9	$ 349.1

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If 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 asset or liability. Fair 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. 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 as well as any letters of credit that they have provided.

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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 and liabilities. 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 market 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 11 Risk Management and Hedging Activities.

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.

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 input that requires the highest degree of judgment in the determination of the instrument s fair value. 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.

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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. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. 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 an active 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 relationship 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 use interest rate swap and forward-starting interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our existing floating rate debt for fixed-rate debt and lock in rates on our anticipated future fixed-rate debt, respectively. Our swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR instrument. Given that a portion of the swap 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 and entity valuation adjustments in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Nonfinancial Assets and Liabilities

We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3, in the event that we were required to measure and record such assets at fair value within our consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement

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obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

We utilize fair value on a recurring basis to measure our contingent consideration that is a result of certain acquisitions. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and are classified within Level 3.

The following table presents the financial instruments carried at fair value as of December 31, 2012 and 2011, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets (a):								
Commodity derivatives	$	$ 9.4	$ 40.0	$ 49.4	$	$ 40.1	$ 1.1	$ 41.2
Long-term assets (b):								
Commodity derivatives	$	$ 5.1	$ 64.7	$ 69.8	$	$ 5.4	$ 1.0	$ 6.4
Current liabilities (c):								
Commodity derivatives	$	$ (26.7)	$ (0.2)	$ (26.9)	$	$ (43.1)	$ (0.7)	$ (43.8)
Interest rate derivatives	$	$ (4.1)	$	$ (4.1)	$	$ (16.1)	$	$ (16.1)
Long-term liabilities (d):								
Commodity derivatives	$	$ (5.5)	$ (0.2)	$ (5.7)	$	$ (27.5)	$ (0.3)	$ (27.8)
Interest rate derivatives	$	$ (2.0)	$	$ (2.0)	$	$ (5.0)	$	$ (5.0)

(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.

Changes in Levels 1 and 2 Fair Value Measurements

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. 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. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. The determination to classify a financial instrument within Level 1 or Level 2 is based upon the availability of quoted prices for identical or similar assets and liabilities in active markets. Depending upon the information readily observable in the market, and/or the use of identical or similar quoted prices, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period. In the event that there is a movement between the classification of an instrument as Level 1 or 2, the transfer between Level 1 and Level 2 would be reflected in a table as Transfers in/out of Level 1/Level 2. During the year ended December 31, 2012, there were no transfers between Level 1 and Level 2 of the fair value hierarchy.

Changes in Level 3 Fair Value Measurements

The tables below illustrate 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

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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. The significant unobservable inputs used in determining fair value include adjustments by other market based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. 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 into/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.

	Commodity Derivative Instruments (Millions)			
	Current Assets	**Long-Term Assets**	**Current Liabilities**	**Long-Term Liabilities**
Year ended December 31, 2012 (a):				
Beginning balance	$ 1.1	$ 1.0	$ (0.7)	$ (0.3)
Net realized and unrealized gains included in earnings (d)	14.3	2.2		0.1
Transfers into Level 3 (c)				
Transfers out of Level 3 (c)				
Settlements	(2.3)		0.5	
Purchases	26.9	61.5		
Ending balance	$ 40.0	$ 64.7	$ (0.2)	$ (0.2)
Net unrealized gains (losses) still held included in earnings (d)	$ 13.2	$ 2.2	$ (0.3)	$ 0.2
Year ended December 31, 2011 (b):				
Beginning balance	$ 0.3	$ 0.3	$ (0.1)	$ (0.5)
Net realized and unrealized gains (losses) included in earnings (d)	1.4	0.8	(0.8)	0.2
Transfers into Level 3 (c)				
Transfers out of Level 3 (c)		(0.1)		
Settlements	(0.6)		0.2	
Ending balance	$ 1.1	$ 1.0	$ (0.7)	$ (0.3)
Net unrealized gains (losses) still held included in earnings (d)	$ 1.1	$ 0.7	$ (0.7)	$ 0.1
Year ended December 31, 2010:				
Beginning balance	$ 1.2	$ 0.7	$ (1.6)	$ (0.7)
Net realized and unrealized gains (losses) included in earnings (d)	2.1	0.8	(0.3)	0.2

Transfers into Level 3 (c)								
Transfers out of Level 3 (c)		(0.5)				0.3		
Purchases, Issuances and Settlements, net		(2.5)		(1.2)		1.5		
Ending balance	$	0.3	$	0.3	$	(0.1)	$	(0.5)
Net unrealized gains (losses) still held included in earnings (d)	$	0.3	$	0.1	$	(0.1)	$	(0.1)

(a) There were no issuances and sales of derivatives for the year ended December 31, 2012.

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(b) There were no purchases, issuances and sales of derivatives for the year ended December 31, 2011.

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

(d) Represents the amount of total gains or losses for the year, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains or losses relating to assets and liabilities classified as Level 3

During years ended December 31, 2012, 2011 and 2010, we had no transfers into or out of Levels 1 and 2. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period.

Quantitative Information and Fair Value Sensitivities Related to Level 3 Unobservable Inputs

We utilize the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

Product Group	Fair Value (Millions)	Forward Curve Range	
Assets			
NGLs	$ 98.6	$ 0.25-$2.13	Per gallon
Natural Gas	$ 6.1	$ 3.69-$4.48	Per MMBtu
Liabilities			
Natural Gas	$ (0.4)	$ 3.81-$4.27	Per MMBtu

Estimated Fair Value of Financial Instruments

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 relationship 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 based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The prices supported by quoted market prices and other external sources category includes our interest rate swaps, our NGL and crude oil swaps, and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service 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

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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.

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 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. Derivative instruments are carried at fair value. Each of the carrying and fair values of outstanding balances under our Credit Agreement are $525.0 million as of December 31, 2012, and $497.0 million as of December 31, 2011. The carrying value of the 2.50% Senior Notes was $500.0 million as of December 31, 2012, which approximated fair value. The carrying and fair values of the 4.95% Senior Notes are $350.0 million and $373.9 million, respectively, as of December 31, 2012. The carrying and fair values of the 3.25% Senior Notes are $250.0 million and $258.8 million, respectively, as of December 31, 2012. The carrying value of the 3.25% Senior Notes as of December 31, 2011 was $250.0 million, which approximated fair value. We determine the fair value of our Credit Agreement borrowings based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We determine the fair value of our fixed-rate debt based on quotes obtained from bond dealers. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy.

10. Debt

Long-term debt was as follows:

	December 31, 2012	December 31, 2011
	(Millions)	
Credit Agreement		
Revolving credit facility, weighted-average variable interest rate of 1.47% and 1.69%, respectively, due November 10, 2016 (a)	$ 525.0	$ 497.0
Debt Securities		
Issued November 27, 2012, interest at 2.50% payable semi-annually, due December 1, 2017	500.0	
Issued March 13, 2012, interest at 4.95% payable semi-annually, due April 1, 2022	350.0	
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250.0	250.0
Unamortized discount	(4.7)	(0.2)
Total long-term debt	$ 1,620.3	$ 746.8

(a) $150.0 million has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.94% to 2.99%, for a net effective rate of 2.25% on the $525.0 million of outstanding debt under our revolving credit facility as of December 31, 2012. $450.0 million was swapped to a fixed-rate obligation with effective fixed rates ranging from 2.94% to 5.19%, for a net effective rate of 4.86% on the $497.0 million of outstanding debt under our revolving credit facility as of December 31, 2011.

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Credit Agreement

We have a $1.0 billion revolving credit facility that matures November 10, 2016, or the Credit Agreement.

At December 31, 2012 and 2011, we had $1.0 million and $1.1 million, respectively, of letters of credit issued and outstanding under the Credit Agreement and the Prior Credit Agreement. As of December 31, 2012, the unused capacity under the Credit Agreement was $474.0 million, which was available for general working capital purposes.

Our borrowing capacity is limited at December 31, 2012 by the Credit Agreement s financial covenant requirements. Except in the case of a default, amounts borrowed under our Credit Agreement will not mature prior to the November 10, 2016 maturity date.

Under the Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) LIBOR, plus an applicable margin of 1.25% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A. s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.25% based on our current credit rating. The revolving credit facility incurs an annual facility fee of 0.25% based on our current credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

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 following the consummation of qualifying acquisitions, not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated.

Debt Securities

On November 27, 2012, we issued $500.0 million of our 2.50% 5-year Senior Notes due December 1, 2017. We received net proceeds of $493.6 million, net of underwriters fees, related expenses and unamortized discounts of $6.4 million. Interest on the notes will be paid semi-annually on June 1 and December 1 of each year, commencing June 1, 2013. The notes will mature on December 1, 2017, unless redeemed prior to maturity. The underwriters fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

On March 13, 2012, we issued $350.0 million of our 4.95% 10-year Senior Notes due April 1, 2022. We received net proceeds of $345.8 million, net of underwriters fees, related expenses and unamortized discounts of $4.2 million, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. The notes will mature on April 1, 2022, unless redeemed prior to maturity. The underwriters fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

On September 30, 2010, we issued $250.0 million of our 3.25% Senior Notes due October 1, 2015. We received net proceeds of $247.7 million, net of underwriters fees, related expense and unamortized discounts of $2.3 million, which we used to repay funds borrowed under the revolver portion of our Credit Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters fees and related expense are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

The notes are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under our Credit Agreement. We are not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at our option.

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Term Loan Agreements

On November 2, 2012, we entered into a 2-year Term Loan Agreement and borrowed $343.5 million to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford system. On July 2, 2012, we entered into a 2-year Term Loan Agreement and borrowed $140.0 million to fund the cash portion of the acquisition of the Mont Belvieu fractionators. In November 2012, we repaid both the term loans with proceeds from our 2.50% 5-year Senior Notes.

On January 3, 2012, we entered into a 2-year Term Loan Agreement and borrowed $135.0 million which was used to fund the cash portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

The future maturities of long-term debt in the year indicated are as follows:

	Debt Maturities (Millions)
2013	$
2014	
2015	250.0
2016	525.0
Thereafter	850.0
	1,625.0
Unamortized discount	(4.7)
Total	$ 1,620.3

11. Risk Management and Hedging Activities

Our day to day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures with both physical and financial transactions. 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. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The following briefly describes each of the risks that we manage.

Commodity Price Risk

Cash Flow Protection Activities 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, sales and storage activities. For gathering, processing and storage services, we may receive cash or commodities as payment for these services, depending on the contract type. We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2016 with commodity derivative instruments. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices, however there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. During 2012, the relationship of NGLs to crude oil has been lower than historical

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relationships, however a significant amount of our NGL hedges from 2012 through 2015 are direct product hedges. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Our crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange our floating price risk for a fixed price. We also utilize crude oil costless collars that minimize our floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that we use to mitigate a portion of our risk may vary depending upon our risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within our consolidated statements of operations as a gain or a loss on commodity derivative activity.

Our Wholesale Propane Logistics segment 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 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. However, 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. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions, including fixed price sales. While the majority of our sales and purchases in this segment are index-based, occasionally, we may enter into fixed price sales agreements in the event that a propane distributor desires to purchase propane from us on a fixed price basis. In such cases, we may manage this risk with derivatives that 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 use financial derivatives to manage the value of our propane inventories. These transactions are not designated as hedging instruments for accounting purposes and any change in fair value is reflected in the current period within our consolidated statements of operations as a gain or loss on commodity derivative activity.

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting, whereby changes in fair value are recorded directly to the consolidated statements of operations; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting.

Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

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Commodity Cash Flow Hedges On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas and commodity derivative hedge instruments (also referred to as the NGL Hedge) related to the Southeast Texas storage business.

During 2011, Southeast Texas commenced an expansion project to build an additional storage cavern. Upon completion of the expansion project, Southeast Texas will be required to purchase a significant amount of base gas to bring the storage cavern to operation. To mitigate risk associated with the forecasted purchase of natural gas in June, July and August 2013, Southeast Texas executed a series of derivative financial instruments, which have been designated as cash flow hedges. These cash flow hedges were in a loss position of $3.3 million as of December 31, 2012 and will fluctuate in value through the term of construction. Any effective changes in fair value of these derivative instruments will be deferred in AOCI until the underlying purchase of inventory occurs. While the cash paid or received upon settlement of these hedges will economically offset the cash required to purchase the base gas, following completion of the additional storage cavern, any deferred gain or loss at the time of the purchase will remain in AOCI until the cavern is emptied and the base gas is sold.

In order for storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. To mitigate the risk associated with the forecasted re-purchase of base gas, in 2008 we executed a series of derivative financial instruments, which were designated as cash flow hedges. The cash paid upon settlement of these hedges economically offsets the cash paid to purchase the base gas. As a result, a deferred loss of $2.7 million was recognized and will remain in AOCI until such time that our cavern is emptied and the base gas is sold.

Interest Rate Risk

We mitigate a portion of our interest rate risk with interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations.

At December 31, 2011, we had interest rate swap agreements totaling $450.0 million, of which we had designated $425.0 million as cash flow hedges and accounted for the remaining $25.0 million under the mark-to-market method of accounting. In March 2012, we paid down a portion of the revolving credit facility and, as a result, we discontinued cash flow hedge accounting on $225.0 million of our interest rate swap agreements. $300.0 million of swap agreements settled in Q2 2012.

At December 31, 2012, we had interest rate swap agreements extending through June 2014 totaling $150.0 million, which are designated as cash flow hedges. Based on our current operations, we believe our interest rate swap agreements mitigate our interest rate risk associated with our variable-rate debt. At December 31, 2012, $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 2.94% to 2.99%, and receive interest payments based on the one-month LIBOR.

Effectiveness of our interest rate swap agreements designated as cash flow hedges 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 and are reclassified into earnings as the hedged transactions impact earnings. The effect that these swaps have on our consolidated financial statements, as well as the effect that is expected over the upcoming 12 months is summarized in the charts below. 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.

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On March 8, 2012, we settled $195.0 million of our forward-starting interest rate swap agreements for $6.6 million. The remaining net deferred losses of $4.7 million in AOCI will be amortized into interest expense associated with our long-term debt offering through 2022.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swap Dealers Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

If we were to have an effective event of default under our Credit Agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.

In the event that we or DCP Midstream, LLC were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.

Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under those agreements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Credit Agreement. As of December 31, 2012, we are not a party to any agreements that would be subject to these provisions other than our Credit Agreement.

Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features.

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position. As of December 31, 2012, we had $22.2 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of December 31, 2012 if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2012, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $20.0 million.

As of December 31, 2012, we had $150.0 million of individual interest rate swap instruments that were in a net liability position of $6.1 million and were subject to credit-risk related contingent features. If we were to have a default of any of our covenants to our Credit Agreement, that occurs and is continuing, the counterparties to our swap instruments have the right to request that we net settle the instrument in the form of cash.

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Unconsolidated Affiliates

Discovery Producer Services LLC, one of our unconsolidated affiliates, entered into agreements with a pipe vendor denominated in a foreign currency in connection with the expansion of the natural gas gathering pipeline system in the deepwater Gulf of Mexico, the Keathley Canyon Connector. Discovery entered into certain foreign currency derivative contracts to mitigate a portion of the foreign currency exchange risks which were designated as cash flow hedges. As these hedges are owned by Discovery, an unconsolidated affiliate, we include the impact to AOCI on our consolidated balance sheet.

Collateral

DCP Midstream, LLC had issued and outstanding parental guarantees totaling $25.0 million in favor of certain counterparties to our commodity derivative instruments. These parental guarantees reduce the amount of cash we may be required to post as collateral. As of December 31, 2012, we had no cash collateral posted with counterparties to our commodity derivative instruments.

Summarized Derivative Information

The following summarizes the balance within AOCI relative to our commodity, interest rate and foreign currency cash flow hedges:

	December 31, 2012	December 31, 2011
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (5.9)	$ (1.8)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(9.5)	(19.4)
Foreign currency cash flow hedges (a):		
Net deferred gain in AOCI	0.7	
Total AOCI	$ (14.7)	$ (21.2)

(a) Relates to Discovery, our unconsolidated affiliate.

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The fair value of our derivative instruments that are designated as hedging instruments and those that are marked to market each period, as well as the location of each within our consolidated balance sheets, by major category, is summarized as follows:

Balance Sheet Line Item	December 31, 2012	December 31, 2011	Balance Sheet Line Item	December 31, 2012	December 31, 2011
	(Millions)			(Millions)	
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (3.3)	$
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term		(2.6)
	$	$		$ (3.3)	$ (2.6)
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (4.1)	$ (15.7)
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term	(2.0)	(5.0)
	$	$		$ (6.1)	$ (20.7)
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments current	$ 49.4	$ 41.2	Unrealized losses on derivative instruments current	$ (23.6)	$ (43.8)
Unrealized gains on derivative instruments long-term	69.8	6.4	Unrealized losses on derivative instruments long-term	(5.7)	(25.2)
	$ 119.2	$ 47.6		$ (29.3)	$ (69.0)
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$	$ (0.4)
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term		
	$	$		$	$ (0.4)

The following table summarizes the impact on our consolidated balance sheet and consolidated statements of operations of our derivative instruments that are accounted for using the cash flow hedge method of accounting for each of the years ended December 31, 2012 and 2011:

	Gain (Loss) Recognized in AOCI on Derivatives Effective Portion		Gain (Loss) Reclassified From AOCI to Earnings Effective Portion		Gain (Loss) Recognized in Income on Derivatives Ineffective Portion and Amount Excluded From Effectiveness Testing		Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	2012	2011	2012	2011	2012	2011	
	(Millions)		(Millions)		(Millions)		(Millions)
Interest rate derivatives	$ (0.7)	$ (12.4)	$ (10.6)	$ (20.4)(a)	$ (2.1)	$ (0.2)(a)(d)	$ (3.6)
Commodity derivatives	$ (0.5)	$ (0.9)	$	$ (0.3)(b)	$ (0.1)	$ (c)	$
Foreign currency derivatives (e)	$ 0.7	$	$	$	$	$	$

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(a) Included in interest expense in our consolidated statements of operations.

(b) Included in sales of natural gas, propane, NGLs and condensate in our consolidated statements of operations.

(c) For the years ended December 31, 2012 and 2011, 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. The ineffective portion is included in gains (losses) from commodity derivative activity, net affiliates in our consolidated statements of operations.

(d) For the year ended December 31, 2012, $0.6 million of derivative 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.

(e) Relates to Discovery, our unconsolidated affiliate.

Changes in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the consolidated statements of operations. The following summarizes these amounts and the location within the consolidated statements of operations that such amounts are reflected:

Commodity Derivatives: Statements of Operations Line Item	Year Ended December 31, 2012	2011 (Millions)	2010
Third party:			
Realized	$ 4.1	$ (36.4)	$ 15.9
Unrealized	13.1	43.2	(10.6)
Gains from commodity derivative activity, net	$ 17.2	$ 6.8	$ 5.3
Affiliates:			
Realized	$ 44.4	$ 1.7	$ (1.2)
Unrealized	8.3	(0.8)	(1.1)
Gains (losses) from commodity derivative activity, net affiliates	$ 52.7	$ 0.9	$ (2.3)

Interest Rate Derivatives: Statements of Operations Line Item	Year Ended December 31, 2012	2011 (Millions)	2010
Third party:			

Realized	$ (7.5)	$ (4.6)	$ (1.5)
Unrealized	7.4	5.2	3.1
Interest expense	$ (0.1)	$ 0.6	$ 1.6

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

DCP MIDSTREAM PARTNERS, LP

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The following tables represent, by commodity type, our net long or short positions that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the tables below.

	December 31, 2012			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	**Net (Short) Position (Bbls)**	**Net (Short) Position (MMBtu)**	**Net (Short) Position (Bbls)**	**Net Long (Short) Position (MMBtu)**
2013	(943,379)	(8,887,980)	(2,593,955)	9,690,000
2014	(584,365)	(4,712,880)	(2,584,930)	(1,350,000)
2015	(401,865)	(5,127,155)	(2,491,250)	
2016	(183,000)			

	December 31, 2011			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	**Net (Short) Position (Bbls)**	**Net (Short) Long Position (MMBtu)**	**Net (Short) Position (Bbls)**	**Net Long Position (MMBtu)**
2012	(695,792)	(17,766,000)	(478,236)	14,357,500
2013	(941,323)	1,635,000		3,600,000
2014	(547,500)	(365,000)		
2015	(365,000)			
2016	(183,000)			

We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of December 31, 2012, we have swaps with a notional value of $70.0 million and $80.0 million, which, in aggregate, exchange $150.0 million of our floating rate obligation to a fixed rate obligation through June 2014.

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, as defined below, to unitholders of record on the applicable record date, as determined by our general partner.

In November 2012, we issued 1,912,663 common units to DCP Midstream, LLC as partial consideration for our 33.33% interest in the Eagle Ford system.

In July 2012, we issued 1,536,098 common units to DCP Midstream, LLC as partial consideration for the Mont Belvieu fractionators.

In July 2012, we closed a private placement of equity with a group of institutional investors in which we sold 4,989,802 common units at a price of $35.55 per unit, and received proceeds of $173.8 million net of offering costs.

In June 2012, we filed a universal shelf registration statement on Form S-3 with the SEC with an unlimited offering amount, to replace an existing shelf registration statement. The universal shelf registration statement allows us to issue additional common units and debt securities. As of February 22, 2013, we have issued no equity securities under this registration statement. Our 2.50% 5-year Senior Notes were issued under this registration statement.

In March 2012, we issued 5,148,500 common units at $47.42 per unit. We received proceeds of $234.0 million, net of offering costs.

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In March 2012, we issued 1,000,417 common units to DCP Midstream, LLC as partial consideration for the remaining 66.67% interest in Southeast Texas.

In February 2012, we issued 30,701 common units under our 2005 Long-Term Incentive Plan, or 2005 LTIP, to employees as compensation for their service.

In January 2012, we issued 727,520 common units to DCP Midstream, LLC as partial consideration for the remaining 49.9% interest in East Texas.

In August 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, common units having an aggregate offering amount of up to $150.0 million. As of December 31, 2012, approximately $69.5 million aggregate offering price of our common units remains available for sale pursuant to this equity distribution agreement. During the three months ended December 31, 2012, we issued 254,265 of our common units pursuant to the equity distribution agreement, and received proceeds of $10.0 million, net of commissions and offering costs of $0.7 million. During the year ended December 31, 2012, we issued 1,147,654 of our common units pursuant to the equity distribution agreement, and received proceeds of $47.4 million, net of commissions and offering costs of $1.6 million. During the year ended December 31, 2011, we issued 761,285 of our common units pursuant to this equity distribution agreement, and received proceeds of $30.2 million from the issuance of these common units, net of commissions and offering costs of $1.2 million.

In March 2011, we issued 3,596,636 common units at $40.55 per unit. We received proceeds of $139.7 million, net of offering costs.

In February 2011, we issued 8,399 common units, from our LTIP to employees as compensation for their service during 2010, 2009 and 2008.

In November 2010, we issued 2,875,000 common units at $34.96 per unit. We received proceeds of $96.2 million, net of offering costs.

In August 2010, we issued 2,990,000 common units at $32.57 per unit. We received proceeds of $93.1 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; and
  - provide funds for distributions to the unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

General Partner Interest and Incentive Distribution Rights The general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 1% and limited partner interest of 1% as of December 31, 2012. 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 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 our common unit issuances, and will not be reduced if we

DCP MIDSTREAM PARTNERS, LP

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

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

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, which ended in February 2009, 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.

The following table presents our cash distributions paid in 2012, 2011 and 2010:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
November 14, 2012	$ 0.6800	$ 52.6
August 14, 2012	$ 0.6700	$ 49.4
May 15, 2012	$ 0.6600	$ 42.6
February 14, 2012	$ 0.6500	$ 36.7
November 14, 2011	$ 0.6400	$ 34.9
August 12, 2011	$ 0.6325	$ 34.0
May 13, 2011	$ 0.6250	$ 33.4
February 14, 2011	$ 0.6175	$ 30.0
November 12, 2010	$ 0.6100	$ 27.4
August 13, 2010	$ 0.6100	$ 25.3
May 14, 2010	$ 0.6000	$ 24.6
February 12, 2010	$ 0.6000	$ 24.6

13. Equity-Based Compensation

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

	Year Ended December 31,		
	2012	2011	2010
		(Millions)	
Performance Phantom Units	$ 0.7	$ 4.2	$ 1.2
Phantom Units	0.2	0.2	0.2
Restricted Phantom Units	0.7	2.2	1.4
Total compensation cost	$ 1.6	$ 6.6	$ 2.8

On November 28, 2005, the board of directors of our General Partner adopted a Long-Term Incentive Plan, or the 2005 LTIP, for employees, consultants and directors of our General Partner and its affiliates who

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perform services for us. The 2005 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 issued and delivered pursuant to awards under the 2005 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.

On February 15, 2012, the board of directors of our General Partner adopted a 2012 LTIP for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 2012 LTIP provides for the grant of phantom units and the grant of DERs. The phantom units consist of a notional unit based on the value of common units or shares of the Partnership, Spectra Energy, ConocoPhillips and Phillips 66.

The LTIPs were administered by the compensation committee of the General Partner s board of directors through 2012, and by the General Partner s board of directors beginning in 2013. All awards are subject to cliff vesting.

Prior to February 18, 2011, substantially all equity-based awards were accounted for as liability awards. Effective February 18, 2011, the Modification Date, we have the intent and ability to settle certain awards within our control in units and therefore modified the accounting for these awards. We classified them as equity awards based on their re-measured fair value. The fair value was determined based on the closing price of our common units on the Modification Date. Such modification resulted in a reclassification of $1.9 million from share-based compensation liability to additional paid-in capital on the Modification Date. Compensation expense on unvested equity awards as of the Modification Date is recognized ratably over each remaining vesting period.

We account for other awards, which are subject to settlement in cash, as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period for all awards outstanding until the units are vested. The fair value of all liability awards is determined based on the closing price of our common units at each measurement date.

The reclassification of the affected awards did not impact our accounting for dividend equivalent rights as these instruments will continue to be settled in cash and therefore retain their share-based compensation liability classification.

Performance Phantom Units We have awarded Performance Phantom Units, or PPUs, pursuant to the LTIP to certain employees. PPUs generally vest in their entirety at the end of a three year performance period. The number of PPUs that will ultimately vest range, in value up to 200% of the outstanding PPUs, depending on the achievement of specified performance targets over three year performance periods. The final performance payout is determined by the board of directors of our General Partner. The DERs are paid in cash at the end of the performance period. Of the remaining PPUs outstanding at December 31, 2012, 3,633 units are expected to vest on December 31, 2013 and 6,377 units are expected to vest on December 31, 2014.

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At December 31, 2012, there was approximately $0.2 million of unrecognized compensation expense related to the PPUs that is expected to be recognized over a weighted-average period of 2 years. The following table presents information related to the PPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2010	67,140	$ 15.18	
Granted	16,630	$ 31.80	
Vested	(14,215)	$ 33.44	
Forfeited	(2,205)	$ 15.61	
Outstanding at December 31, 2010	67,350	$ 15.42	
Granted	10,580	$ 41.80	
Vested	(50,720)	$ 10.05	
Forfeited		$	
Outstanding at December 31, 2011	27,210	$ 35.69	
Granted (a)	11,740	$ 39.31	
Vested (b)	(20,100)	$ 34.57	
Forfeited	(7,760)	$ 38.97	
Outstanding at December 31, 2012	11,090	$ 39.24	$ 41.24
Expected to vest (c)	10,010	$ 39.24	$ 41.24

(a) Includes the impact of conversion of the underlying securities granted under the 2012 LTIP.

(b) The units vested at 121%.

(c) Based on our December 31, 2012 estimated achievement of specified performance targets, the performance estimate for units granted in 2012 is 100%, and for units granted in 2011 is 100%. The estimated forfeiture rate for units granted in both 2012 and 2011 is 10%.

The estimate of PPUs 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.

The following table presents the fair value of units vested and the unit-based liabilities paid related to PPUs, including the related DERs:

	Year Ended December 31,		
	2012	2011	2010
		(Millions)	
Fair value of units vested	$ 1.0	$ 5.3	$
Unit-based liabilities paid	$ 4.5	$	$ 0.8

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.

As part of their director fees, we granted 4,000 Phantom Units during each of the years ended December 31, 2012 and 2011, respectively, and 5,200 Phantom Units during the year ended December 31, 2010, to directors. All of these units vested in their respective grant years, and were settled in units.

The DERs are paid in cash quarterly in arrears.

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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, 2010		$	
Granted	5,200	$ 24.05	
Vested	(5,200)	$ 31.80	
Outstanding at December 31, 2010		$	
Granted	4,000	$ 41.80	
Vested	(4,000)	$ 41.80	
Outstanding at December 31, 2011		$	
Granted	4,000	$ 48.03	
Vested	(4,000)	$ 48.03	
Outstanding at December 31, 2012		$	$

The following table presents the fair value of units vested related to Phantom Units:

	Year Ended December 31, 2012	2011	2010
		(Millions)	
Fair value of units vested	$ 0.2	$ 0.2	$ 0.2

Restricted Phantom Units Our General Partner s board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. Of the remaining RPUs outstanding at December 31, 2012, 1,560 units are expected to vest on December 31, 2013 and 1,610 units are expected to vest on December 31, 2014. The DERs are paid in cash quarterly in arrears.

At December 31, 2012, there was approximately $0.1 million of unrecognized compensation expense related to the RPUs that is expected to be recognized over a weighted-average period of 2 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, 2010	67,140	$ 15.18	
Granted	16,630	$ 31.80	
Vested	(14,215)	$ 33.44	

Forfeited	(2,205)	$ 15.61		
Outstanding at December 31, 2010	67,350	$ 15.42		
Granted	10,580	$ 41.80		
Vested	(58,600)	$ 12.97		
Forfeited		$		
Outstanding at December 31, 2011	19,330	$ 37.27		
Granted (a)	11,740	$ 39.31		
Vested	(19,060)	$ 37.31		
Forfeited	(7,760)	$ 43.27		
Outstanding at December 31, 2012	4,250	$ 39.63	$ 41.31	
Expected to vest	3,170	$ 39.76	$ 41.34	

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(a) Includes the impact of conversion of the underlying securities granted under the 2012 LTIP.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to Restricted Phantom Units:

	Year Ended December 31,		
	2012	2011	2010
		(Millions)	
Fair value of units vested	$ 1.2	$ 2.5	$ 0.5
Unit-based liabilities paid	$ 2.4	$ 0.6	$

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 30% for units granted in 2012 and 20% for units granted in 2011. 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.

14. Income Taxes

We are structured as a master limited partnership with sufficient qualifying income, which is a pass-through entity for federal income tax purposes. Accordingly, we had no federal income tax expense for the years ended December 31, 2012 and 2010.

On December 30, 2010, we acquired all of the interests in Marysville Hydrocarbons Holdings, LLC, an entity that owned a taxable C-Corporation consolidated return group. We estimated $35.0 million of deferred tax liabilities resulting from built-in tax gains recognized in the transaction and recorded this as part of our preliminary acquisition accounting as of December 31, 2010. On January 4, 2011, we merged two wholly-owned subsidiaries of Marysville Hydrocarbons Holding, LLC and converted the combined entity s organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggered the deferred tax liabilities resulting from built-in tax gains to become currently payable. Accordingly, the estimated $35.0 million of deferred tax liabilities at December 31, 2010 became currently payable on January 4, 2011. During 2011, we made federal and state tax payments of $29.3 million and $0.3 million, respectively, related to our estimated $35.0 million tax liability that resulted from our acquisition of Marysville. In 2011, the remaining $5.4 million estimated tax payable was reclassified to goodwill in our final acquisition accounting for the Marysville business combination.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. For the years ended December 31, 2011 and 2010, the state of Michigan imposed 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 was subject to a tax surcharge of 21.99%. The Michigan business tax was repealed for the year ended December 31, 2012.

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Income tax expense consists of the following:

	Year Ended December 31,		
	2012	2011	2010
		(Millions)	
Current:			
Federal income tax expense	$	$ (29.3)	$
State income tax expense	(1.0)	(1.3)	(1.1)
Deferred:			
Federal income tax benefit		29.3	
State income tax (expense) benefit		0.8	(0.4)
Total income tax expense	$ (1.0)	$ (0.5)	$ (1.5)

We had net long-term deferred tax liabilities of $3.4 million as of December 31, 2012 and 2011, included in other long-term liabilities on the consolidated balance sheets. These state deferred tax liabilities relate to our East Texas operations, and are primarily associated with depreciation related to property plant and equipment.

Our effective tax rate differs from statutory rates, primarily due to being structured as a master limited partnership, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states

15. 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, through the date of subordinated conversion, in accordance with their respective ownership percentages, after allocating Available Cash generated during the period in accordance with our partnership agreement.

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 our Available Cash it will have the impact of reducing net income per LPU.

Basic and diluted net income or loss per LPU is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the year. Diluted net income or loss per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Dilutive potential units include outstanding Performance Units, Phantom Units and Restricted Units. The dilutive effect of unit-based awards was 33,043 and 64,286 equivalent units during the years ended December 31, 2012 and 2011.

16. Commitments and Contingent Liabilities
Litigation

Prospect During the fourth quarter of 2011, we received a claim for arbitration (the Claim) filed with the American Arbitration Association by Prospect Street Energy, LLC and Prospect Street Ventures I, LLC (together, the Claimants) against EE Group, LLC (EE Group) and a number of other parties that previously

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owned, directly or indirectly, our Marysville NGL storage facility (collectively, the Respondents). EE Group is our indirect subsidiary which we acquired in connection with our acquisition of Marysville Hydrocarbons Holdings, LLC (Marysville) on December 30, 2010 (the Acquisition). The Claim involves actions taken and time periods prior to our ownership of EE Group and Marysville, and includes several causes of action including claims of civil conspiracy, breach of fiduciary duty and fraud. We acquired a 90% interest in Marysville from Dart Energy Corporation, a 5% interest in Marysville from Prospect Street Energy, LLC and a 100% interest in EE Group, which owned the remaining 5% interest in Marysville. The Claimants seek, from the Respondents collectively, alleged actual, punitive and treble damages and disgorgement of profits, as well as fees and costs. The purchase agreements for the Acquisition contain indemnification and other provisions that may provide some protection to us for any breach of the representations, warranties and covenants made by the sellers in the Acquisition. In August 2012, we entered into a Settlement Agreement with the Claimants in which the Claimants have agreed that if an award is issued to the Claimants in the arbitration, the Claimants will not attempt to recover such an award from us. Notwithstanding that agreement, this matter is subject to the uncertainties inherent in any litigation, and the ultimate outcome of this matter may not be known for an extended period of time.

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 flow.

Insurance We renewed our insurance policies in May, June and July 2012 for the 2012-2013 insurance year. We contract with third party and affiliate insurers for: (1) automobile liability insurance for all owned, non-owned and hired vehicles; (2) general liability insurance; (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 real and personal property and includes business interruption/extra expense. These renewals have not resulted in any material change to the premiums we are contracted to pay in the 2012-2013 insurance year compared with the 2011-2012 insurance year. We are jointly insured with DCP Midstream, LLC for 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 that are of similar size to us and with similar types of operations.

Our insurance on Discovery for the 2012-2013 insurance year includes general and excess liability, onshore property damage, including named windstorm and business interruption, and offshore non-wind property and business interruption insurance. The availability of offshore named windstorm property and business interruption insurance has been significantly reduced over the past few years as a result of higher industry-wide damage claims. Additionally, the named windstorm property and business interruption insurance that is available comes at uneconomic premium levels, higher deductibles and lower coverage limits. As such, Discovery has elected to not purchase offshore named windstorm property and business interruption insurance coverage for the 2012-2013 insurance year.

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,

DCP MIDSTREAM PARTNERS, LP

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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.

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, $13.1 million and $12.8 million for the years ended December 31, 2012, 2011 and 2010, 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, 2012:

	(Millions)
2013	$ 10.8
2014	5.6
2015	3.5
2016	2.4
2017	1.1
Thereafter	0.9
Total minimum rental payments	$ 24.3

17. Business Segments

Our operations are located in the United States and are organized into three reporting segments: Natural Gas Services; NGL Logistics; and Wholesale Propane Logistics.

Natural Gas Services Our Natural Gas Services segment provides services that include gathering, compressing, treating, processing, transporting and storing natural gas. The segment consists of our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our Michigan system, our Southeast Texas system, our East Texas system, our 75% interest in the Colorado system, our 40% interest in Discovery, and our 33.33% interest in the Eagle Ford system.

NGL Logistics Our NGL Logistics segment provides services that include transportation, storage and fractionation of NGLs. The segment consists of the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, our 10% interest in the Texas Express NGL pipeline, the NGL storage facility in Michigan, the DJ Basin NGL fractionators in Colorado, our 12.5% interest in the Mont Belvieu Enterprise fractionator, and our 20% interest in the Mont Belvieu 1 fractionator.

Wholesale Propane Logistics Our Wholesale Propane Logistics segment provides services that include the receipt of propane by pipeline, rail or ship to our terminals that deliver the product to distributors. The segment consists of six owned rail terminals, one owned marine terminal, one leased marine terminal, one pipeline terminal and access to several open-access pipeline terminals.

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.

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The following tables set forth our segment information:

Year Ended December 31, 2012:

	Natural Gas Services	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations (f)	Total
			(Millions)			
Total operating revenue	$ 1,242.7	$ 63.5	$ 414.7	$	$ (0.2)	$ 1,720.7
Gross margin (a)	$ 314.0	$ 63.5	$ 41.7	$	$	$ 419.2
Operating and maintenance expense	(92.4)	(16.1)	(14.7)			(123.2)
Depreciation and amortization expense	(54.7)	(6.2)	(2.5)			(63.4)
General and administrative expense				(45.8)		(45.8)
Earnings from unconsolidated affiliates	17.6	11.3				28.9
Other operating income		0.5				0.5
Interest expense				(42.2)		(42.2)
Income tax expense (b)				(1.0)		(1.0)
Net income (loss)	184.5	53.0	24.5	(89.0)		173.0
Net income attributable to noncontrolling interests	(5.0)					(5.0)
Net income (loss) attributable to partners	$ 179.5	$ 53.0	$ 24.5	$ (89.0)	$	$ 168.0
Net unrealized gains on derivative instruments (c)	$ 19.8	$	$ 1.5	$	$	$ 21.3
Capital expenditures	$ 185.0	$ 11.8	$ 3.6	$	$	$ 200.4
Acquisitions net of cash acquired	$ 657.6	$ 29.8	$	$	$	$ 687.4
Investments in unconsolidated affiliates	$ 141.3	$ 42.7	$	$	$	$ 184.0

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Years Ended December 31, 2012, 2011 and 2010 (Continued)

Year Ended December 31, 2011:

	Natural Gas Services	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations (f)	Total
			(Millions)			
Total operating revenue	$ 1,670.4	$ 56.6	$ 633.6	$	$ (2.2)	$ 2,358.4
Gross margin (a)	$ 322.3	$ 52.0	$ 51.1	$	$	$ 425.4
Operating and maintenance expense	(94.7)	(15.9)	(15.1)			(125.7)
Depreciation and amortization expense	(89.5)	(8.2)	(2.9)			(100.6)
General and administrative expense				(48.3)		(48.3)
Earnings from unconsolidated affiliates	22.7					22.7
Other operating income		0.5				0.5
Interest expense				(33.9)		(33.9)
Income tax expense (b)				(0.5)		(0.5)
Net income (loss)	160.8	28.4	33.1	(82.7)		139.6
Net income attributable to noncontrolling interests	(18.8)					(18.8)
Net income (loss) attributable to partners	$ 142.0	$ 28.4	$ 33.1	$ (82.7)	$	$ 120.8
Net unrealized gains on derivative instruments (c)	$ 41.8	$	$ 0.3	$ (2.2)	$	$ 39.9