DCP Midstream Partners, LP
Form 10-K
February 29, 2012
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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, 2011

or

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

Commission file number: 001-32678

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

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

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

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

Title of Each Class:	**Name of Each Exchange on Which Registered:**

Common Units Representing Limited Partner Interests	New York Stock Exchange

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

NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1934, or the Act. Yes 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 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. x

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, 2011, was approximately $1,348,670,000. 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, 2011.

As of February 23, 2012, there were outstanding 45,606,924 common units.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

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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, 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 acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets 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 or by the fuel markets;
- our ability to purchase propane from our principal suppliers and make associated profitable sales transactions for our wholesale propane logistics business;
- our ability to construct facilities 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;

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

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

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- 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, or we, us, our, or the partnership, is a Delaware limited partnership formed in August 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We completed our initial public offering on December 7, 2005. We are currently engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; transporting, storing and selling propane in wholesale markets; and producing, fractionating, transporting, storing and selling NGLs and condensate. Supported by our relationship with DCP Midstream, LLC and its parents, Spectra Energy Corp, or Spectra Energy, and ConocoPhillips, we have a management team dedicated to executing our growth strategy by acquiring and constructing additional assets. During the third quarter of 2011, ConocoPhillips announced plans to separate its business into two stand-alone publicly traded companies, and anticipates completing the proposed separation during the first half of 2012. As a result of this potential transaction, DCP Midstream, LLC would no longer be owned 50% by ConocoPhillips. ConocoPhillips 50% ownership interest in DCP Midstream, LLC will be transferred to the new downstream company, Phillips 66. We do not anticipate that the change in ownership will have a material impact on our business or operations.

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:

Co-investment with DCP Midstream, LLC: maximize opportunities provided by our partnership with DCP Midstream, LLC. We plan to execute and fund our growth in part through co-investing with DCP Midstream, LLC, which can take numerous forms: (1) We pursue direct investments or third party acquisitions of assets with characteristics that are suited to our master limited partnership where those assets are part of a larger strategic investment for our partnership and DCP Midstream, LLC. (2) We pursue organic build projects in which we provide the capital to construct all or part of an asset within DCP Midstream, LLC s footprint. Size of the capital investment, its cash flow, contract profile and capital availability are key determinants for selection of an organic build project. (3) We pursue accretive acquisition/dropdown opportunities from DCP Midstream, LLC and through the formation of additional joint ventures with 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, LLC s footprint, we would expect relatively more emphasis on our co-investment objective over the next few years.

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. We 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 parents. Our relationship with DCP Midstream, LLC and its parents, Spectra Energy and ConocoPhillips, should continue to provide us with significant business opportunities. DCP Midstream, LLC is one of the largest gatherers of natural gas (based on wellhead volume), and one of the largest producers and marketers of NGLs in North America. This relationship also provides us with access to a significant pool of management talent. We believe our strong relationships throughout the energy industry, including with major producers of natural gas and NGLs in the United States, will help facilitate the implementation of our strategies. Additionally, we believe DCP Midstream, LLC, which operates 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, wholesale propane, NGL 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 parents, 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 26% limited partner interest in us. We have entered into an omnibus agreement, or the Omnibus Agreement, with DCP Midstream, LLC and some of its affiliates that governs our relationship among them regarding the operation of most of our assets, as well as certain reimbursement and other matters.

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 Colorado, Louisiana, Michigan, Oklahoma, Texas, Wyoming and the Gulf of Mexico. These natural gas gathering systems provide a variety of services to our customers including natural gas gathering, compression, treating, processing, fractionation, 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 Colorado, Kansas, Louisiana and Texas, 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 an underground NGL storage facility along the Gulf Coast. Our NGL storage facility 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. Our supply agreement with Spectra Energy is effective through April 30, 2012. We are currently assessing several available options for future supply sources. 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 of DCP Midstream, LLC and former senior officers from 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

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, compression, treating, processing, transporting, storing and selling of natural gas, and the production, fractionating, transporting, storing and selling of 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 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 retail distributors.

Production of Propane

Propane is extracted from the natural gas stream at processing plants, separated from NGLs at fractionation facilities or separated from crude oil during the refining process. Most of the propane that is consumed in the United States is produced at processing plants, fractionation facilities and refineries located in the United States or in foreign locations, particularly Canada, the North Sea, East Africa and the Middle East. There are limited 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 propane production and relatively high demand, the mid-Atlantic and northeastern United States are importers of propane. These areas rely almost exclusively 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.

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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.

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 varying array of wellhead to market services for our producer customers. These services include gathering, compressing, treating, processing, transporting and storing natural gas; however, we do not offer all services at every location. These assets are positioned in 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 Northern Louisiana system (including the Minden, Ada and Pelico systems), our Southern Oklahoma system (Lindsay system), our 40% limited liability company interest in the Discovery system located off and onshore in Southern Louisiana, our East Texas system (in which we acquired the remaining 49.9% interest that we did not previously own from DCP Midstream, LLC in January 2012), our 75% operating interest in our Colorado system (Collbran system), our Wyoming system (Douglas system), our Michigan system, and our 33.33% equity interest in the Southeast Texas system. 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 5,300 miles of pipe, eleven processing plants, five treating plants, one natural gas storage facility and two NGL fractionation facilities. The eleven processing

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plants that service our natural gas gathering systems include ten cryogenic facilities with approximately 873 MMcf/d of processing capacity and one refrigeration facility with approximately 45 MMcf/d of processing capacity. Further, our Minden and Discovery processing facilities both have ethane rejection capabilities that serve to optimize the value of the gas stream. The natural gas storage facilities include 850 MMcf of leased storage on our Pelico system, and our 33.33% interest in the Southeast Texas system s 9 Bcf salt dome storage facility. In addition to our existing assets, we are constructing a 200 MMcf/d cryogenic natural gas processing plant in the Eagle Ford shale, or the Eagle plant, that we expect to be completed by the fourth quarter of 2012 and an additional storage cavern at Southeast Texas that we expect to be completed by the third quarter of 2013.

During 2011, the volume throughput on our assets was in excess of 1.2 Bcf/d, originating from a diversified mix of natural gas producing companies. 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 2011, the combined NGL production from our processing facilities was in excess of 39,000 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:

	2011 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)**
Minden	725	1(c)		115		65	4,170
Ada	130	1(c)		45		41	146
Pelico	600				1(e)	115	
Southern Oklahoma	225					18	2,005
Colorado	40	1(d)		84		58	2,183
Wyoming	1,300					25	2,316
Michigan	440	4(d)		455		321	
Discovery	300	1(c)(e)	1(e)	240		188	8,017
East Texas	900	5(c)(f)	1	391		273	13,771
Southeast Texas	675	3(c)		127	3(b)	105	6,818
Total	5,335	16	2	1,457	4	1,209	39,426

(a) Represents total capacity or total volumes allocated to our proportionate ownership share for 2011 divided by 365 days. We have a 40% limited liability company interest in Discovery, 75% interest in our Colorado system, 50.1% interest in East Texas and 33.33% interest in Southeast Texas.

(b) Represents total storage capacity allocated to our proportionate ownership share.

(c) Represents NGL extraction plants.

(d) Represents treating plants.

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

(f) Our East Texas complex comprises 5 cryogenic processing plants.

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 processing plant has amine treating and ethane recovery and rejection capabilities such that we can recover approximately 80% of the ethane contained in the natural gas stream. In addition, the processing plant is able to reject the majority of the ethane when justified by market economics. This processing flexibility enables us to maximize the value of ethane for our customers. NGLs produced at the Minden processing plant are delivered to our Black Lake pipeline.

Our Ada gathering system is located in Bienville and Webster Parish 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. The NGLs produced at the Ada processing plant are transported by truck from the plant tailgate.

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 storage capacity from a third party.

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 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, along with Delta Petroleum Corporation, are the producers on the system. The Collbran system underwent expansion, completed in the third quarter of 2009, which consisted of an additional 24-inch pipeline loop and installation of compression at the Anderson Gulch site. The expansion increased the pipeline capacity to 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 Wyoming system consists of over 1,300 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.

Our Michigan system consists of four natural gas treating plants and an approximately 330-mile gas gathering pipeline system with throughput capacity of 455 MMcf/d; an approximately 55-mile residue gas pipeline, or 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.

Effective January 3, 2012, we own a 100% interest in DCP East Texas Holdings, LLC, or East Texas. In July 2007, April 2009 and January 2012, we acquired 25.0%, 25.1% and 49.9%, respectively, of the limited liability company interests in East Texas from DCP Midstream, LLC. Our East Texas system gathers, transports, compresses, treats and processes natural gas and NGLs. Our East Texas facility may also fractionate NGL production, 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 780 MMcf/d and fractionation capacity of 11MBbls/d.

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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 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, operated by the Williams Companies, offers a full range of wellhead-to-market services to both onshore and offshore natural gas producers. The assets are primarily located in the eastern Gulf of Mexico and Lafourche Parish, Louisiana. The Discovery system is able to reject the majority of the ethane when justified by market economics. 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 intends to construct 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.

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

We have a 33.33% interest in DCP Southeast Texas Holdings, GP, or Southeast Texas, which we acquired from DCP Midstream, LLC in January 2011. Two wholly-owned subsidiaries of DCP Midstream, LLC own the remaining 66.67% interest. 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 recently increased processing capacity totaling 400 MMcf/d, and natural gas storage assets in Beaumont with 9 Bcf of existing storage capacity. On February 27, 2012, we entered into agreements with DCP Midstream, LLC, to acquire the remaining 66.67% interest in Southeast Texas, and natural gas commodity derivatives associated with the storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. This acquisition is expected to close by the second quarter of 2012.

Southeast Texas is managed by a three-member management committee, consisting of one representative appointed by us and two representatives from DCP Midstream, LLC. The members of the management committee have voting power corresponding to their respective ownership interests in Southeast Texas. Southeast Texas must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The terms of the joint venture agreement provide that distributions to us for the first seven years related to natural gas storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Midstream, LLC s respective ownership interests in Southeast Texas. In the event Southeast Texas has insufficient available cash for a quarterly distribution, DCP Midstream, LLC will assign its distribution rights (including pursuant to our fee-based arrangement), or contribute any distribution deficiency to Southeast Texas, the sole use of which shall be to pay the distribution deficiency owing to us related to our fee-based arrangement on natural gas storage and transportation gross margin, based on storage capacity and tailgate volumes. The allocation of earnings to each owner is made on the same basis as the above cash distributions. The management committee, by majority approval, will determine the amount of the distributions.

Our Eagle plant is under construction and will have a planned processing capacity of 200 MMcf/d, will process DCP Midstream, LLC s natural gas volumes and enhance DCP Midstream, LLC s existing South Texas system comprised of five natural gas processing plants totaling approximately 800 MMcf/d of capacity. The processing agreement commences with commercial operations of the new plant, which is expected to be online by the fourth quarter of 2012. The Eagle plant will be connected to the Trunkline Gas pipeline system and liquids rich gas will be received from various DCP Midstream, LLC gathering systems by Trunkline for delivery into the Eagle plant.

Natural Gas and NGL Markets

The Northern Louisiana system has numerous market outlets for the natural gas that we gather on the system. Our natural gas pipelines connect to the Perryville Market Hub, a natural gas marketing hub that provides connection to four intrastate or interstate pipelines, including pipelines owned by Southern Natural Gas Company, Texas Gas Transmission, LLC, CenterPoint Energy Mississippi River Transmission Corporation and CenterPoint Energy Gas Transmission Company. In addition, our natural gas pipelines in northern Louisiana also have access to gas that flows through pipelines owned by Texas Eastern Transmission, LP, Crosstex LIG, LLC, Gulf South Pipeline Company, Tennessee Natural Gas Company and Regency Intrastate Gas, LLC. The Northern Louisiana system is also connected to eight major industrial end-users and makes deliveries to three power plants. The NGLs extracted from the natural gas at the Minden processing plant are delivered to our Black Lake pipeline through our Minden NGL pipeline. The Black Lake pipeline delivers NGLs to Mt. Belvieu. The NGLs extracted from natural gas at the Ada processing plant are sold at market index prices to affiliates and are delivered to third parties trucks at the tailgate of the plant.

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

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

The Wyoming system delivers to the Kinder Morgan Interstate Gas Transmission interstate pipeline. The NGLs on the Wyoming system are transported on the ConocoPhillips-owned Powder River Pipeline.

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

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

The Southeast Texas system has numerous 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 Eagle plant will be connected to the Trunkline Gas pipeline system. Liquids rich gas will be received from several of DCP Midstream, LLC s gathering systems by Trunkline for delivery into the Eagle plant. Residue gas will also be redelivered to Trunkline at the tailgate of the Eagle plant.

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, Wyoming and Southern Oklahoma are processed under percent-of-proceeds contracts. Discovery has percent-of-liquids contracts and fee-based contracts, as well as some 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 and Ada assets, as well as our Colorado and Michigan system, are fee-based.

DCP Midstream, LLC operates our Southeast Texas system storage facility. It commits on an annual basis a portion of such facility s capacity to third parties pursuant to fee-based arrangements and manages the rest for its own account. We receive distributions related to this storage business pursuant to the Southeast Texas joint venture agreement.

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 our construction of the 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 in length of term and therefore must be renegotiated on a more frequent basis.

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NGL Logistics Segment

General

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

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 2011, had average throughput of approximately 62 MBbls/d. Our pipelines provide transportation services to customers on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to recover NGLs from natural gas because of the higher value of natural gas compared to the value of NGLs. As a result, we have experienced periods in the past, and will likely experience periods in the future, when higher 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 in Colorado, or DJ Basin, separate NGLs received from processing plants into their individual component parts. The DJ Basin NGL Fractionators 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 and was operating near capacity in 2011. 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.

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NGL Pipelines

Following is operating data for our NGL pipelines:

System	Approximate System Length (Miles)	2011 Operating data Approximate Capacity (MBbls/d) (a)	Pipeline Throughput (MBbls/d) (a)
Seabreeze	56	41	20
Wilbreeze	39	11	11
Wattenberg (b)	480	22	13
Black Lake	317	40	18
Total	892	114	62

(a) Represents total throughput for 2011 divided by 365 days.

(b) The Wattenberg capital expansion project was completed in May 2011.

Seabreeze and Wilbreeze Pipelines. The Seabreeze intrastate NGL pipeline is approximately 56 miles long, has capacity of 41 MBbls/d and, in 2011, had average throughput of approximately 20 MBbls/d. The Seabreeze pipeline, located in Texas, receives NGLs from a large third-party processing plant with capacity of approximately 340 MMcf/d located in Matagorda County and two NGL pipelines. The Seabreeze pipeline is the sole NGL pipeline for one processing plant and is the delivery point for two NGL pipelines, the Wilbreeze Pipeline and Enterprise s Dean Pipeline. One third party NGL pipeline is capable of transporting NGLs from five natural gas processing plants located in south Texas that have aggregate processing capacity of approximately 1.6 Bcf/d. Three of these processing plants are owned by DCP Midstream, LLC. In total, seven processing plants produce NGLs, which flow into the Seabreeze pipeline from processed natural gas produced in south Texas and the Gulf of Mexico. The Seabreeze pipeline delivers the NGLs it receives from these sources to a third party fractionator, and its associated party storage facility. The Wilbreeze intrastate pipeline, located in Texas, is approximately 39 miles long, has a current capacity of 11 MBbls/d and, in 2011, had average throughput of 11 MBbls/d.

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 four DCP Midstream, LLC plants, two of which were connected in 2011 to address the growing needs in the DJ Basin. These plants ultimately deliver to the MAPL pipeline.

Black Lake Pipeline. The Black Lake interstate NGL pipeline is approximately 317 miles long, has capacity of 40 MBbls/d and, in 2011, had average throughput of approximately 18 MBbls/d. The Black Lake pipeline delivers NGLs from processing plants in northern Louisiana and southeastern Texas to fractionation plants at Mt. Belvieu on the Texas Gulf Coast. The Black Lake pipeline receives NGLs from two natural gas processing plants in northern Louisiana, including our Minden plant and Regency Intrastate Gas, LLC s Dubach processing plant. The Black Lake pipeline is the sole NGL pipeline for these natural gas processing plants in northern Louisiana, as well as one of our Southeast Texas system processing plants, and also receives NGLs from XTO Energy Inc. s Cotton Valley processing plant and Eagle Rock s Brookland processing plant.

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.

NGL Fractionation Facilities

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

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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

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 receives its supply of NGLs that it then transports on the Seabreeze pipeline under an NGL purchase agreement with Williams Field Services Gulf Coast Company, LP. Under this agreement, Williams has dedicated all of their respective NGL production from this processing plant to DCP Midstream, LLC. DCP Midstream, LLC has a sales agreement with Formosa Hydrocarbons Company, Inc. Additionally, DCP Midstream, LLC has a transportation agreement with TEPPCO Partners, L.P. that covers all of the NGL volumes transported on TEPPCO Partners, L.P. s South Dean NGL pipeline for delivery to the Seabreeze pipeline.

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.

There are currently four active shippers on the Black Lake pipeline. DCP Midstream, LLC has historically been the largest, accounting for approximately 38% of total throughput in 2011. The Black Lake pipeline generates revenues through a FERC-regulated tariff.

DCP Midstream, LLC supplies certain committed NGLs produced by them in Weld County to our DJ Basin NGL Fractionators under fee-based agreements that are effective through March 2018.

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 the storage are primarily fee-based.

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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 retail propane distribution customers with reliable, low cost deliveries and greater volumes of propane during periods of tight supply such as the winter months. We believe these factors generally result in our maintaining favorable relationships with our customers and allowing us to remain a supplier to many of the large retail 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 retail 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. Additionally, we are actively seeking new terminals through acquisition or construction to expand our distribution capabilities.

Our Terminals

Our operations include one owned propane marine import 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

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marine terminal is on a long-term 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 under index-based pricing. The remaining supply is purchased on annual or 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, Spectra Energy and BP Canada. We may also obtain supply from our NGL storage facility in Marysville, Michigan. Our supply agreement with Spectra Energy is effective through April 30, 2012. We are currently assessing several available options for future supply sources.

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. We have supply contracts with Spectra Energy for both marine terminals.

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.

Customers and Contracts

We typically sell propane to retail propane distributors under annual sales agreements, negotiated each spring, that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year. We manage this commodity price risk by 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, approximately 75% of the gross margin generated by our wholesale propane business is earned in the heating season months of October through April, which corresponds to the general market demand for propane.

We had 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.

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 18 of the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

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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. The U.S. Department of Transportation, or DOT, has developed regulations implementing the Pipeline Safety Improvement Act that requires pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. We currently estimate we will incur costs of up to $6.7 million between 2012 and 2016 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.

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

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in 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

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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 $40.0 million and aggregate disgorgements of approximately $6.0 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 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. For violations occurring before August 8, 2005, FERC had the authority to impose civil penalties for violations of the NGPA up to $5,000 per violation per day. The Pelico and EasTrans systems are subject to FERC jurisdiction under Section 311 of the NGPA.

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 are subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

Our purchasing, gathering and intrastate transportation operations are subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels 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.

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

Environmental Matters

General

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

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

- requiring the acquisition of permits to conduct regulated activities;
- restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operations;

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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.

Air Emissions, Global Warming and Climate Change

Our operations are subject to the federal Clean Air Act of 1963, as amended and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, and utilize specific emission control technologies to limit emissions. In response to studies suggesting that emissions of carbon dioxide and certain other gases often referred to as greenhouse gases, or GHGs, may be contributing to warming of the Earth s atmosphere, the U.S. Congress continues to consider climate change-related legislation to regulate GHG emissions. In addition, almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. 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, following the EPA s finding that GHGs endanger public health and welfare the EPA adopted two sets of regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another that regulates GHG emissions from certain large stationary sources under the Clean Air Act Prevention of Significant Deterioration (PSD) and Title V permitting programs. In addition, EPA expanded its existing GHG emissions reporting rule to include onshore oil and natural gas processing, transmission, storage, and distribution activities, beginning in 2012 for emissions occurring in 2011. In part, these programs could require our facilities to meet best available control technology standards for greenhouse gases, which may be established by state authorities or the EPA on a case-by-case basis. In November 2010, the EPA issued guidance materials on defining best available control technology for greenhouse gases. Litigation challenging the EPA s endangerment finding and its related regulatory enactments is pending before the DC Circuit. These EPA regulations as well as other possible new federal or state laws or regulations imposing more stringent air quality standards for hazardous air

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pollutants or ambient air quality standards or requiring adoption of stringent GHG reporting and control programs or imposing restrictions on emissions of carbon dioxide in areas of the United States in which we conduct business could adversely affect our cost of doing business and demand for the oil and gas we transport. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

In addition to the effects of regulation, the meteorological effects of global climate change could pose additional risks to our operations, including physical damage risks associated with more frequent, more intense storms and flooding, and could adversely affect the demand for our products.

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.

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, 2011, the General Partner or its affiliates employed 6 people directly and approximately 334 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.

Item 1A. ***Risk Factors***

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. You should consider carefully the following risk factors together with all of the other information included in this annual report in evaluating an investment in our common units.

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

Risks Related to Our Business

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

The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, level of production of, and demand for natural gas, propane, condensate and NGLs;
- the success of our commodity 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 propane and NGLs we transport, sell, and store;
- the relationship between natural gas, NGL and crude oil prices;
- the level of competition from other energy companies;
- the impact of weather conditions on the demand for natural gas and propane;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;

the cost and form of payment for acquisitions;

our debt service requirements and other liabilities;

fluctuations in our working capital needs;

our ability to borrow funds and access capital markets at reasonable rates;

restrictions contained in our debt agreements;

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

the amount of cash reserves established by our general partner; and

new, additions to and changes in laws and regulations.

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We have partial ownership interests in certain joint venture legal entities, including Discovery and Southeast Texas, 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 $3.24, $4.55 and $5.87 as of December 31, 2011, 2010 and 2009, respectively. The twelve-month average price per gallon for NGLs was $1.39, $1.10 and $0.80 as of December 31, 2011, 2010 and 2009, respectively, and the price of crude oil per barrel was $95.12, $79.53 and $61.81 as of December 31, 2011, 2010 and 2009, respectively. Crude oil and natural gas liquids prices continue to be volatile, but have generally remained at favorable levels, while natural gas prices have declined substantially. Natural gas drilling activity levels vary by geographic area, but in general, drilling remains robust in areas with liquids rich gas. Drilling remains depressed in certain areas with dry gas where low natural gas prices currently do not support the economics of drilling.

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 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 revolving credit facility 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.

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.

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, 2011. In our NGL Logistics segment, our largest NGL supplier is DCP Midstream, LLC, who obtains NGLs from various third party producer customers. While some of these customers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts on favorable terms, if at all. The loss of all or even a portion of the natural gas and NGL volumes supplied by these customers, as a result of competition or otherwise, could have a material adverse effect on our business.

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

Most of our propane purchases are made under supply contracts that have a term of between one to five years and provide various pricing formulas. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our three primary suppliers of propane, two of which are affiliated entities, represented approximately 88% of our propane supplied during the year ended December 31, 2011. Forty-three percent of our propane supply is provided by Spectra Energy. The propane supply agreement with Spectra Energy expires April 30, 2012. We are currently assessing several available options for future supply sources. A portion of our suppliers propane is sourced by them internationally. If current unrest in North Africa should expand further into countries where our propane supply originates, it could result in supply disruptions. 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 under our rail commitments, 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 has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Although certain bona fide hedging transactions or positions would be exempt from these position limits, it is not possible at this time to predict what impact these regulations will have on our hedging program or when the CFTC will finalize these regulations. The Act may also require us to comply with margin requirements and with certain clearing and trade-execution 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 any new regulations could significantly increase the cost of derivatives contracts (including through 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. 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:

- 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;
- participate in co-investment opportunities with DCP Midstream, LLC;
- 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 retail distributors. We may not be successful in balancing our purchases and sales. A producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to be unbalanced. While we attempt to balance our purchases and sales, if our purchases and sales are unbalanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income and cash flows.

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

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

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets.

The majority of our natural gas gathering and intrastate transportation operations are exempt from FERC regulation under the NGA but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC s policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of regular litigation, so the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on any reassessment by us of the jurisdictional status of our facilities or on future determinations by FERC and the courts.

In addition, the rates, terms and conditions of some of the transportation services we provide on our Pelico pipeline system and the EasTrans Limited Partnership or EasTrans pipeline system owned by East Texas, are subject to FERC regulation under Section 311 of the NGPA. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The Pelico system is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under a rate settlement approved by FERC. The EasTrans system is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under an

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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

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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 our business, financial condition and results of operations. We cannot predict with any certainty what form any additional regulation or limitations would take.

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 currently 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 will most likely consider a number of bills 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 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.

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

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

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

Although many of our natural gas facilities fall within a class that is not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with non-exempt 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, 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 $6.7 million between 2012 and 2016 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial.

We currently transport 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. 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

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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.

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. 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.

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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, storage and transporting 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 facility, 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. 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.

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. 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 investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the ratings agencies and no assurance can be given that we will maintain our 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 facility. Our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- an increased amount of cash flow will be required to make interest payments on our debt;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to obtain new debt funding or service our existing debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors. In addition, our ability to service debt under our revolving credit facility will depend on market interest rates. If our operating results are not sufficient to service our current or future indebtedness, we may take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all.

Restrictions in our loan agreement may limit our ability to make distributions to unitholders and may limit our ability to capitalize on acquisitions and other business opportunities.

Our loan agreement contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our loan agreement contains covenants requiring us to maintain a certain leverage ratio and certain other tests. Any subsequent replacement of our loan agreement 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 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, 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, 2011, 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, 2011, our consolidated indebtedness was $746.8 million. 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 facility 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 or the attacks in London, and the threat of future terrorist attacks on our industry in general, and on us in particular, is not known at this time. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East 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;

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- 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.

Risks Inherent in an Investment in Our Common Units

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Cost reimbursements due to our general partner and its affiliates for services provided, which will be determined by our general partner, will be material.

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

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

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, DCP Midstream, LLC. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement permits our general partner to make a number of decisions either in its individual capacity, as opposed to in its capacity as our general partner or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- the exercise of its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;

- its limited call right;

- its voting rights with respect to the units it owns;

its registration rights; and

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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.