Blueknight Energy Partners, L.P.
Form 10-K
March 13, 2012

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 001-33503

BLUEKNIGHT ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-8536826 (I.R.S. Employer Identification No.)
Two Warren Place 6120 South Yale Avenue, Suite 500 Tulsa, Oklahoma (Address of principal executive offices)	74136 (Zip Code)

(918) 237-4000
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units representing limited partner interests	Nasdaq Global Market
Series A Preferred Units representing limited partner interests	Nasdaq Global Market

Securities Registered Pursuant to Section 12(g) of the Act:

None

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

Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No 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 Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements the past 90 days.

Yes x No o

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

As of June 30, 2011, the aggregate market value of the registrant's common units held by non-affiliates of the registrant was approximately $92.1 million, based on $8.05 per common unit, the closing price of the common units as reported on the Pink Sheets over-the-counter securities market on such date.

At March 9, 2012, there were 22,660,137 common units and 30,159,958 Series A Preferred Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
None

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DEFINITIONS

We use the following terms in this report:

Barrel: One barrel of petroleum products equals 42 United States gallons.

Bpd: Barrels per day.

Common carrier pipeline: A pipeline engaged in the transportation of petroleum products as a public utility and common carrier for hire.

Condensate: A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Feedstock: A raw material required for an industrial process such as in petrochemical manufacturing.

Finished asphalt products: As used herein, the term refers to liquid asphalt cement sold directly to end users and to asphalt emulsions, asphalt cutbacks, polymer modified asphalt cement and related asphalt products processed using liquid asphalt cement. The term is also used to refer to various residual fuel oil products directly sold to end users.

Liquid asphalt cement: Liquid asphalt cement is a dark brown to black cementitious material that is primarily produced by petroleum distillation. When crude oil is separated in distillation towers at a refinery, the heaviest hydrocarbons with the highest boiling points settle at the bottom. These tar-like fractions, called residuum, require relatively little additional processing to become products such as asphalt cement or residual fuel oil. Liquid asphalt cement is primarily used in the road construction and maintenance industry. Residual fuel oil is primarily used as a burner fuel in numerous industrial and commercial business applications. As used herein, the term refers to both liquid asphalt cement and residual fuel oils.

Midstream: The industry term for the components of the energy industry in between the production of oil and gas (upstream) and the distribution of refined and finished products (downstream).

PMAC: Polymer modified asphalt cement.

Preferred Units: Series A Preferred Units represents limited partnership interests in our partnership.

SemCorp: SemCorp refers to SemGroup Corporation and its predecessors (including SemGroup, L.P.), subsidiaries and affiliates (other than our General Partner and us during periods in which we were affiliated with SemGroup, L.P.). SemCorp and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware, Case No. 08-11547-BLS. We were not a party to SemCorp's bankruptcy filings.

Terminalling: The receipt of crude oil and petroleum products for storage into storage tanks and other appurtenant equipment, including pipelines, where the crude oil and petroleum products will be commingled with other products of similar quality; the storage of the crude oil and petroleum products; and the delivery of the crude oil and petroleum products as directed by a distributor into a truck, vessel or pipeline.

Throughput: The volume of product transported or passing through a pipeline, plant, terminal or other facility.

PART I

As used in this annual report, unless we indicate otherwise: (1) “Blueknight Energy Partners,” “our,” “we,” “us” and similar terms refer to Blueknight Energy Partners, L.P. (f/k/a/ SemGroup Energy Partners, L.P.), together with its subsidiaries, (2) our “General Partner” refers to Blueknight Energy Partners G.P., L.L.C. (f/k/a SemGroup Energy Partners G.P., L.L.C.), (3) “Vitol” refers to Vitol Holding B.V., its affiliates and subsidiaries (other than our General Partner and us) and (4) “Charlesbank” refers to Charlesbank Capital Partners, LLC, its affiliates and subsidiaries (other than our General Partner and us).

Forward Looking Statements

This report contains “forward-looking statements” within the meaning of the federal securities laws. Statements included in this annual report that are not historical facts (including any statements regarding plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto) are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “may,” “will,” “should,” “believe,” “expect,” “intend,” “anticipate,” “estimate,” “continue,” or other similar words. These state discuss future expectations, contain projections of results of operations or of financial condition, or state other “forward-looking” information. We and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

Such forward-looking statements are subject to various risks and uncertainties that could cause actual results to differ materially from those anticipated as of the date of this report. Although we believe that the expectations reflected in these forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to be correct. Important factors that could cause our actual results to differ materially from the expectations reflected in these forward-looking statements include, among other things, those set forth in “Item 1A—Risk Factors,” included in this annual report, and those set forth from time to time in our filings with the Securities and Exchange Commission (“SEC”), which are available through the Investor Relations link at www.bkep.com and through the SEC’s Electronic Data Gathering and Retrieval System (“EDGAR”) at http://www.sec.gov.

All forward-looking statements included in this report are based on information available to us on the date of this report. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

Item 1. Business

Overview

We are a publicly traded master limited partnership with operations in twenty-three states. We provide integrated terminalling, storage, processing, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and asphalt product. We manage our operations through four operating segments: (1) crude oil terminalling and storage services, (2) crude oil pipeline services, (3) crude oil trucking and producer field services, and (4) asphalt services. During the fourth quarter of 2010, we changed the structure of our internal organization in a manner that caused the composition of our operating and reportable segments to change. Previously, the crude oil pipeline services segment and the crude oil trucking and producer field services segment were presented on a combined basis.

Our Operational History and Structure

We were formed as a Delaware limited partnership in 2007 to own, operate and develop a diversified portfolio of complementary midstream energy assets. Our operating assets are owned by, and our operations are conducted through, our subsidiaries. Our General Partner has sole responsibility for conducting our business and for managing our operations. Our General Partner is jointly owned by Blueknight Energy Holding, Inc. (which is an affiliate of Vitol) and CB-Blueknight, LLC (which is an affiliate of Charlesbank). As such, Vitol and Charlesbank control our operations. Our General Partner has previously been controlled by other entities. See "Management's Discussion and Analysis of Financial Condition—Our History" for a discussion of these other controlling entities.

Our General Partner has no business or operations other than managing our business. In addition, outside of its investment in us, our General Partner owns no assets or property other than a minimal amount of cash which has been distributed by us to our General Partner in respect of its interest in us. Our partnership agreement imposes no additional material liabilities upon our General Partner or obligations to contribute to us other than those liabilities and obligations imposed on general partners under the Delaware Revised Uniform Limited Partnership Act.

The following diagram depicts our organizational structure, including our relationship with our affiliates and subsidiaries, as of December 31, 2011:
Our Strengths and Strategies

Strategically placed assets. Our primary crude oil terminalling and storage facilities are located within the Cushing Interchange, one of the largest crude oil marketing hubs in the United States and the designated point of delivery specified in all NYMEX crude oil futures contracts. We believe that the Cushing Interchange will continue to serve as one of the largest crude oil marketing hubs in the United States. In addition, we have approximately 1,289 miles of strategically positioned gathering and transportation pipelines in Oklahoma and Texas as well as 44 asphalt terminals located in 22 states that we believe are well positioned to provide services in the market areas they serve throughout the continental United States.

Growth opportunities. Vitol and Charlesbank have indicated that they intend to use us as a growth vehicle to pursue the acquisition and expansion of midstream energy businesses and assets. Vitol and Charlesbank have formed a new company ("Development Company") that they have informed us is intended to be focused on developing projects that we may later have the opportunity to acquire. Further, we may be involved in additional midstream projects for Vitol or Charlesbank outside of Development Company. We have no interest in Development Company. We also cannot say with any certainty whether or not Development Company or Vitol or Charlesbank will develop any projects or, if they do, which, if any, of these future acquisition opportunities may be made available to us, or if we will choose to pursue any such opportunity.

Experienced management team. Our General Partner has an experienced and knowledgeable management team with extensive experience in the energy industry. We expect to directly benefit from this management team's strengths, including significant relationships throughout the energy industry with producers, marketers and refiners of crude oil and customers of our asphalt services.

Our relationship with Vitol and Charlesbank. Vitol and Charlesbank jointly own our General Partner and therefore control our operations. Vitol owns a diversified portfolio of midstream energy assets in the United States and internationally. Charlesbank is a middle-market private equity investment firm based in Boston and New York. These relationships may provide us with additional capital sources for future growth as well as increased opportunities to provide terminalling, storage, processing, gathering and transportation services. While these relationships may benefit us, they may also be a source of potential conflicts. For example, Vitol and Charlesbank are not restricted from competing with us and they 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.

Industry Overview

Crude Oil Industry

We provide crude oil gathering, transportation, storage and terminalling services to producers, marketers and refiners of crude oil products. The market we serve, which begins at the source of production and extends to the point of distribution to the end user customer, is commonly referred to as the "midstream" market. Our crude oil operations are located primarily in Oklahoma, Kansas and Texas, where there are extensive crude oil production operations in place and our assets extend from gathering systems and trucking networks in and around these producing fields to transportation pipelines carrying crude oil to logistics hubs, such as the Cushing Interchange (Cushing, Oklahoma), where we have substantial terminalling and storage facilities that aid our customers in managing the delivery of their crude oil.

Gathering and transportation. Pipeline transportation is generally considered the lowest cost method for shipping crude oil and refined petroleum products to other locations. Crude oil and refined products pipelines transport about two-thirds of the petroleum shipped in the United States. Crude oil pipelines transport oil from the wellhead to logistics hubs and/or refineries. Logistics hubs like the Cushing Interchange provide storage and connections to other pipeline systems and modes of transportation, such as tankers, railroads, and trucks. Vessels and railroads provide additional transportation capabilities shipping crude oil between gathering storage systems, pipelines, terminals and storage centers and end-users. Vessel transportation is typically a cost-efficient mode of transportation that allows for the ability to transport large volumes of crude oil over long distances.

Trucking complements pipeline gathering systems by gathering crude oil from operators at remote wellhead locations not served by pipeline gathering systems. These trucks can also be used to transport crude oil to aggregation points and storage facilities, which are generally located along pipeline gathering and transportation systems. Trucking is generally limited to low volume, short haul movements where other alternatives to pipeline transportation are often unavailable. Trucking costs escalate sharply with distance, making trucking the most expensive mode of crude oil transportation. Despite being small in terms of both volume per shipment and distance, trucking is an essential component of the oil distribution system.

Terminalling and storage.   Terminalling and storage facilities complement the crude oil pipeline gathering and transportation systems. Terminals are facilities where crude oil is transferred to or from a storage facility or transportation system, such as a gathering pipeline, to another transportation system, such as trucks or another pipeline. Terminals play a key role in moving crude oil to end-users such as refineries by providing storage and inventory management and distribution.

Storage and terminalling assets generate revenues through a combination of storage and throughput charges to third parties. Storage fees are generated when tank capacity is provided to third parties. Terminalling services fees, also referred to as throughput services fees, are generated when a terminal receives crude oil from a shipper and redelivers it to another shipper. Both storage and terminalling services fees are earned from refiners and gatherers that need segregated storage for refining feedstocks, pipeline operators, refiners or traders that need segregated storage for foreign cargoes, traders who make or take delivery under NYMEX contracts and producers and marketers that seek to increase their marketing alternatives.

Overview of the Cushing Interchange (Cushing, Oklahoma). The Cushing Interchange is one of the largest crude oil marketing hubs in the United States and the designated point of delivery specified in all NYMEX crude oil futures contracts. As the NYMEX delivery point and a cash market hub, the Cushing Interchange serves as the primary source of refinery feedstock for Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. The following table lists certain of the incoming pipelines connected to the Cushing Interchange, the proprietary terminals within the complex and all outgoing pipelines from the Cushing Interchange for delivery throughout the United States:

Incoming Pipelines to Cushing Interchange	Cushing Interchange Terminals	Outgoing Pipelines from Cushing Interchange
Blueknight Energy Partners, L.P.	Blueknight Energy Partners, L.P.	Blueknight Energy Partners, L.P.
BP p.l.c.	Enterprise Products Partners L.P.	BP p.l.c.
Enterprise Products Partners L.P.	Enbridge Energy Partners, L.P.	ConocoPhillips
Sunoco Logistics Partners, L.P.	Plains All American Pipeline, L.P.	Sunoco Logistics Partners, L.P.
Plains All American Pipeline, L.P.	ConocoPhillips	Enbridge Energy Partners, L.P.
Seaway Crude Pipeline Company	SemGroup Corporation	Osage Pipeline Company, LLC
Enbridge Energy Partners, L.P.	Magellan Midstream Partners, L.P.	Ozark Pipeline
SemGroup Corporation	Deeprock Energy Resources LLC / Kinder Morgan Energy Partners, L.P.	Plains All American Pipeline, L.P.
Basin Pipeline System		Magellan Midstream Partners, L.P.
TransCanada Corp.		Centurion Pipeline L.P.
EOG Resources, Inc.		
White Cliffs Pipeline, LLC		

Due to our pipeline and terminalling infrastructure, we have the ability to receive and/or deliver, directly or indirectly, to all pipelines and terminals within the Cushing Interchange.

Asphalt Industry

Liquid asphalt cement is one of the oldest engineering materials. Liquid asphalt cement's adhesive and waterproofing properties have been used for building structures, waterproofing ships, mummification and numerous other applications.

Production of liquid asphalt cement begins with the production of crude oil. Liquid asphalt cement is a dark brown to black cementitious material that is primarily produced by petroleum distillation. When crude oil is separated in distillation towers at a refinery, the heaviest hydrocarbons with the highest boiling points settle at the bottom. These tar-like fractions, called residuum, require relatively little additional processing to become products such as asphalt base or residual fuel oil. Liquid asphalt cement production typically represents only a small portion of the total product production in the crude oil refining process. The liquid asphalt cement produced by petroleum distillation can be sold by the refinery either directly into the wholesale and retail liquid asphalt cement markets or to a liquid asphalt cement marketer.

In its normal state, asphalt cement is too viscous a liquid to be used at ambient temperatures. For paving applications, asphalt cement can be heated (as for hot mix asphalt), diluted or cut back with petroleum solvents (cutback asphalts), or emulsified in a water base with emulsifying chemicals by a colloid mill (asphalt emulsions). Hot mix asphalt is produced by mixing hot asphalt cement and heated aggregate (stone, sand and/or gravel). The hot mix asphalt is loaded into trucks for transport to the paving site, where it is placed on the road surface by paving machines and compacted by rollers. Hot mix asphalt is used for new construction, reconstruction and for thin maintenance overlays on existing roads.

Asphalt emulsions and cutback asphalts are used for a variety of applications including spraying as a tack coat between an old pavement and a new hot mix asphalt overlay, cold mix pothole patching material, and preventive maintenance surface applications such as chip seals. Asphalt emulsions are also used for fog seal, slurry seal, scrub seal, sand seal and microsurfacing maintenance treatments, for warm mix emulsion/aggregate mixtures, base stabilization and both central plant and in-place recycling. Asphalt emulsions and cutback asphalts are generally sold directly to government agencies, but are also sold to contractors for use in applications such as chip seals.

The asphalt industry in the United States is characterized by a high degree of seasonality. Much of this seasonality is due to the impact that weather conditions have on road construction schedules, particularly in cold weather states. Refineries produce liquid asphalt cement year round, but the peak asphalt demand season is during the warm weather months when most of the road construction activity in the United States takes place. Liquid asphalt cement marketers and finished asphalt product producers with access to extensive storage capacity possess the inherent advantage of being able to purchase supply from refineries on a year round basis and then sell finished asphalt products in the peak summer demand season.

Residual Fuel Oil Industry

Like asphalt cement, residual fuel oil is another by-product of the crude oil distillation process. Residual fuel oil is primarily used as a burner fuel in numerous industrial and commercial business applications including the utility industry, the shipping and paper industry, steel mills, tire manufacturing, schools and food processors.

The residual fuel oil industry in the United States is characterized by a high degree of seasonality with much of the seasonality driven by the impact of weather on the need to produce power for heating and cooling applications. The residual fuel oil market is largely a commodity market with price functioning as the primary decision-making criterion. However, many customers have unique product specifications driven by their particular business applications that require the blending of various components to meet those specifications.

Residual fuel oil is purchased from a variety of refiners by our customers and transported to our terminalling and storage facilities via numerous transportation methods including rail tank car, barge, ship and truck. Some of our customers use our asphalt assets to service their residual fuel oil business.

Crude Oil Terminalling and Storage Services

With approximately 7.8 million barrels of above-ground crude oil terminalling facilities and storage tanks, we are able to provide our customers the ability to effectively manage their crude oil inventories and significant flexibility in their marketing and operating activities. Our crude oil terminalling and storage assets are located throughout our core operating areas with the majority of our crude oil terminalling and storage strategically located at the Cushing Interchange.

Our crude oil terminals and storage assets receive crude oil products from pipelines, including those owned by us, and distribute these products to interstate common carrier pipelines and regional independent refiners, among other third parties. Our crude oil terminals derive most of their revenues from terminalling services fees charged to customers.

The table below sets forth the total average barrels stored at and delivered out of our Cushing terminal in each of the periods presented and the total storage capacity at our Cushing terminal and at our other terminals at the end of such periods:

	Year Ended December 31,	
	2010	2011
Average crude oil barrels stored per month at our Cushing terminal	5,113,699	4,333,964
Average crude oil delivered (Bpd) to our Cushing terminal	62,562	63,696
Total storage capacity at our Cushing terminal (barrels at end of period)	6,713,200	6,600,000
Total other storage capacity (barrels at end of period)	1,396,584	1,217,109

The following table outlines the location of our crude oil terminals and their storage capacities and number of tanks as of December 31, 2011:

Location	Storage Capacity (barrels)	Number of Tanks
Cushing, Oklahoma	6,600,000	34
Longview, Texas	430,000	7
Other(1)	787,109	246
Total	7,817,109	287

(1) Consists of miscellaneous storage tanks located at various points along our pipeline and gathering system.

Cushing Terminal. One of our principal assets is our Cushing terminal, which is located within the Cushing Interchange in Cushing, Oklahoma. Currently, we own and operate 34 crude oil storage tanks with approximately 6.6 million barrels of storage capacity at this location.

We own approximately 10 additional acres of land within the Cushing Interchange that is available for future expansion. This acreage is capable of housing an additional 1.0 million barrels of storage in four above ground tanks.

SemCorp purchased the Cushing terminal in 2000, at which time the facility had approximately 790,000 barrels of storage capacity. The storage capacity of our Cushing terminal was substantially expanded in a series of phases beginning in 2002. Prior to SemCorp’s bankruptcy filings, SemCorp used the Cushing terminal and our other storage assets to conduct its crude oil business and was the primary driver of the increased volumes terminalled and stored each year since SemCorp purchased the assets until it filed for bankruptcy. Subsequent to SemCorp’s bankruptcy filings, we entered into storage agreements with Vitol and various third parties.

Our Cushing terminal was constructed over the last 50 years and has an expected remaining life of at least 20 years. Over 90% of our total storage capacity in our Cushing terminal has been built since 2002. We estimate that our storage tanks have a weighted average age of nine years.

The design and construction specifications of our storage tanks meet or exceed the minimums established by the American Petroleum Institute, or API. Our storage tanks also undergo regular maintenance inspection programs that are more stringent than established governmental guidelines. We believe that these design specifications and inspection programs will result in lower future maintenance capital costs to us.

A key attribute of our Cushing terminal is that through our pipeline and gathering system interface, we have access and connectivity to all the terminals located within the Cushing Interchange. This connectivity is a key attribute of our Cushing terminal because it provides us the ability to deliver to virtually any customer within the Cushing Interchange.

Our Cushing terminal can receive crude oil from our Mid-Continent system as well as other terminals owned by Magellan Midstream Partners, Enterprise Products Partners, Sunoco Logistics Partners, Plains All American, Seaway, Enbridge Energy Partners, SemCorp, Deeprock Energy Resources, EOG Resources, Inc. and two truck racks. Our Cushing terminal’s pipeline connections to major markets in the Mid-Continent region provide our customers with marketing flexibility. Our Cushing terminal can deliver crude oil via pipeline and, in the aggregate, is capable of receiving and/or delivering 348,000 Bpd of crude oil.

Longview Terminal. We own and operate the Longview terminal, located in Longview, Texas, consisting of seven tanks with a total storage capacity of 430,000 barrels. We use our Longview terminal in connection with our Longview system. The Longview terminal can receive and ship crude oil in both directions at the same time. A number of other potential customers have access to the Longview terminal. We acquired the Longview terminal in connection with our initial public offering. The Longview terminal was constructed beginning in the 1940s and we believe it has a remaining life of at least 20 years.

Significant Customers. For the twelve months ended December 31, 2011, Vitol accounted for $27.6 million, or 71%, of our total crude oil terminalling and storage revenue. In addition, Mercuria Energy Trading, Inc. accounted for at least 10% but not more than 25% of crude oil terminalling and storage revenue in 2011. The loss of either of these customers could have a material adverse effect on our business, cash flows and results of operations. One of our storage agreements with Vitol, if not renewed, will expire on June 1, 2012. We recognized revenue of approximately $13.2 million under this contract in 2011. While we are pursuing a renewal of this storage agreement, there can be no assurance that we will be successful in our efforts. No other customer accounted for more than 10% of our crude oil terminalling and storage revenue during 2011.

Crude Oil Pipeline Services

We own and operate a crude oil gathering and transportation system in the Mid-Continent region of the United States with a combined length of approximately 820 miles and a 330 mile tariff-regulated crude oil gathering and transportation pipeline in the Longview, Texas area. In addition, we own and operate the Eagle North Pipeline System in the Mid-Continent region of the United States with a length of approximately 139 miles. The Eagle North Pipeline System was placed in service in December of 2010.

System	Asset Type	Approximate Length (miles)	Average Throughput for Year Ended December 31, 2010 (Bpd)	Average Throughput for Year Ended December 31, 2011 (Bpd)	Pipe Diameter Range
Mid-Continent	Gathering and transportation pipelines	820	18,959	20,019	4” to 20”
Longview	Gathering and transportation pipelines	330	20,851	27,624	6” to 8”
Eagle North	Gathering and transportation pipelines	139	14,874(1)	11,960	8”

(1) Represents average throughput from the time the Eagle North system was placed in service in December 2010 through December 31, 2010.

Mid-Continent System. Our Mid-Continent gathering and transportation system consists of approximately 820 miles of gathering pipelines that, in aggregate, gather wellhead crude oil from approximately 318 pipeline connected wells for transport to our primary transportation systems that provide access to our Cushing terminal and other storage facilities. The Oklahoma portion of our Mid-Continent system consists of approximately 790 miles of various sized pipeline, of which approximately 390 miles is idle, inactive pipe. Crude oil gathered into the Oklahoma portion of our Mid-Continent system is transported to our Cushing terminal or delivered to local area refiners. The Mid-Continent system also includes a small, 34-mile gathering and transportation system in the Texas Panhandle near Dumas, Texas. Crude oil collected through the Texas Panhandle portion of our Mid-Continent system is transported by pipeline to a station where it is then delivered to market via tanker truck. For the years ended December 31, 2010 and 2011, this system gathered an average of approximately 18,959 Bpd and 20,019 Bpd of crude oil, respectively. The Mid-Continent system was constructed in various stages beginning in the 1940s and we believe it has a remaining life of at least 20 years.

Longview System. Our Longview system consists of approximately 330 miles of tariff-regulated crude oil gathering pipeline, of which approximately 100 miles is idle, inactive pipe. The East Texas portion of this system delivers to crude oil terminalling, refinery and storage facilities at various delivery points in the East Texas region. Our Longview system also includes a small pipeline gathering system (Thompson-to-Webster) located near Houston, Texas. The Thompson-to-Webster gathering system consists of 42 miles of 6” and 8” pipeline. Deliveries made from this gathering system are transported to refineries in the Baytown/Texas City area. For the years ended December 31, 2010 and 2011, our Longview system gathered an average of approximately 20,851 Bpd and 27,624 Bpd, respectively. Shippers on the Longview system include Chevron Products Company, Eastex Crude, ExxonMobil Corporation, Jetta Production Company, Plains All American L.P., Shell Trading, Sunoco Logistics Partners L.P., and Tidal Energy Marketing (US) LLC. The Longview system was constructed in various stages beginning in the 1940s and we believe it has a remaining life of at least 20 years.

Eagle North Pipeline System. In May of 2008, we purchased our Eagle North Pipeline System, which includes a 139-mile, 8-inch pipeline that originates in Cushing, Oklahoma and terminates in Ardmore, Oklahoma. In August of 2010, our partnership and Vitol entered into a Throughput Capacity Agreement (the "Throughput Capacity Agreement"). We have entered into a throughput agreement with a third party relating to this pipeline. In addition, pursuant to the Throughput Capacity Agreement, Vitol purchased 100% of the throughput capacity of the Eagle North Pipeline System with its rights being subordinate to the rights of the third party under its throughput agreement with us. For more information relating to the Throughput Capacity Agreement, please see "Item 13. Certain Relationships and Related Transactions, and Director Independence—Agreements with Vitol—Vitol Throughput Capacity Agreement."

In 2010, we spent an additional $6.7 million, including capitalized interest of $3.8 million, to ready this pipeline for service and to extend it from Drumright, Oklahoma to Cushing, Oklahoma. This asset was placed into service in December of 2010.

Significant Customers. ExxonMobil Corporation, Valero Marketing & Supply Co, and Vitol each accounted for at least 10% but not more than 25% of crude oil pipeline services revenue in 2011. The loss of any of these customers could have a material adverse effect on our business, cash flows and results of operations. No other customer accounted for more than 10% of our crude oil pipeline services revenue during 2011.

Crude Oil Trucking and Producer Field Services

We provide two types of trucking services: crude oil trucking and producer field services.

Crude Oil Trucking Services. To complement our pipeline gathering and transportation business, we use our approximately 157 owned or leased tanker trucks, which have an average tank size of approximately 200 barrels. Our tanker trucks moved an average of 46,763 Bpd and 46,826 Bpd, respectively, for the years ended December 31, 2010 and 2011 from wellhead locations not served by pipeline gathering systems to aggregation points and storage facilities. Several of our trucking services operating areas, such as Midland, Texas, are not currently served by our gathering and transportation pipeline systems. In these areas, our trucking operations extend our ability to gather and aggregate crude oil on our systems. This ability allows the crude oil marketing customers we serve to increase the level of service they are able to provide to their customers and facilitates the transportation of incremental volumes on our system. The following table outlines the distribution of our trucking assets among our operating areas as of December 31, 2011:

Location	Number of Trucks
Oklahoma	53
Kansas	26
Borger, Texas	32
Midland, Texas	26
Hobbs, New Mexico	20
Total	157

Normally we assign trucks to a specific area but, when needed, we can temporarily relocate them to meet demand. We dispatch our drivers with advanced computer technology out of central locations in Oklahoma City, Oklahoma and Dumas, Texas. The drivers are provided with hand-held computers and, after loading, the drivers provide the customers with a printed computer generated ticket with the information needed for payment. The hand-held computer can transmit as well as receive needed information to accomplish daily workloads. The drivers are also provided mobile communications to enhance safety and security.

Producer Field Services. We provide a number of producer field services for companies such as Eagle Rock Energy, DCP Midstream and ConocoPhillips. These services include gathering condensates by way of bobtail trucks for natural gas companies to hauling produced water to disposal wells, providing hot and cold fresh water, chemical and down hole well treating, wet oil clean up and building and maintaining separation facilities. We provide these services at contractual hourly rates. Our producer service fleet consists of approximately 123 trucks in a number of different sizes.

Significant Customers. Vitol and MV Purchasing, LLC each accounted for at least 10% but not more than 25% of crude oil trucking and producer field services revenue in 2011. The loss of either of these customers could have a material adverse effect on our business, cash flows and results of operations. No other customer accounted for more than 10% of our crude oil trucking and producer field services revenue during 2011.

Asphalt Services

With approximately 7.2 million barrels of total asphalt product and residual fuel oil storage capacity, we are able to provide our customers the ability to effectively manage their asphalt product storage and processing and marketing activities. Our 44 terminals are located in 22 states and as such are well positioned to provide asphalt services in the market areas they serve throughout the continental United States.

We now serve the asphalt industry by providing our customers access to their market areas through a combination of the leasing of certain of our asphalt facilities and the provision of storage and processing services at other of our asphalt and residual fuel oil facilities. In our asphalt services segment, we generate revenues by charging a fee for the lease of a facility or for services provided as asphalt products are terminalled, stored and/or processed in our facilities.

In addition, we currently have leases and storage agreements with third party customers relating to 43 of our 44 asphalt facilities. The majority of the leases and storage agreements related to these facilities have terms that expire at or near the end of 2016. We operate the asphalt facilities pursuant to the storage agreements while our contract counterparties operate the asphalt facilities that are subject to the lease agreements.

At facilities where we have storage contracts, we receive, terminal, store and/or process our customer’s asphalt products until we deliver these products to our customers or other third parties. Our asphalt assets include the logistics assets, such as docks and rail spurs and the piping and pumping equipment necessary to facilitate the unloading of liquid asphalt cement into our terminalling and storage facilities as well as the processing and manufacturing equipment required for the processing of asphalt emulsions, asphalt cutbacks, polymer modified asphalt cement and other related finished asphalt products. After initial unloading, the liquid asphalt cement is moved via heat-traced pipelines into large storage tanks. These tanks are insulated and contain heating elements that allow the asphalt cement to be stored in a heated state. The asphalt cement can then be directly sold by our customers to end users or used as a raw material for the processing of asphalt emulsions, asphalt cutbacks, polymer modified asphalt cement and related finished asphalt products that we process in accordance with the formulations and specifications provided by our customers. Dependent on the product, the processing of asphalt entails combining asphalt cement and various other products such as emulsifying chemicals and polymers to achieve the desired specification and application requirements.

At leased facilities, our customers conduct the operations at the asphalt facility, including the storage and processing of asphalt products, and we collect a monthly rental fee relating to the lease of such facility. Generally, under the terms of these leases, (i) title to the asphalt, raw materials, or finished asphalt products received, unloaded, stored, or otherwise handled at such asphalt facility is in the name of the lessee, (ii) the lessee is responsible for complying with environmental, health, safety, transportation, and security laws, (iii) the lessee is required to obtain and maintain necessary permits, licenses, plans, approvals, or other such authorizations and is responsible for insuring such asphalt facility, and (iv) most routine maintenance and repair of such asphalt facility is the responsibility of the lessee.

We do not take title to, or marketing responsibility for, the liquid asphalt product that we terminal, store and/or process. As a result, our asphalt operations have minimal direct exposure to changes in commodity prices, but the volumes of liquid asphalt cement we terminal or store are indirectly affected by commodity prices.

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The following table provides an overview of our asphalt facilities as of December 31, 2011:

Location	Number of Facilities	Total Tankage (in thousands of Bbls)(1)
Arkansas	1	21
California	1	66
Colorado	4	401
Georgia	1	38
Idaho	1	285
Illinois	2	232
Indiana	1	156
Kansas	4	492
Michigan	1	171
Missouri	3	643
Montana	1	123
Nebraska	1	292
New Jersey	1	459
Nevada	1	280
Ohio	1	38
Oklahoma	6	864
Pennsylvania	2	72
Tennessee	3	470
Texas	3	779
Utah	2	300
Virginia	1	547
Washington	3	470
Total	44	7,199

(1) Total tankage refers to the approximate total capacity of all tanks.

Our asphalt assets range in age from one year to over fifty years and we expect that our storage tanks and related assets will have an average remaining life of in excess of 20 years.

Significant Customers. NuStar Marketing LLC, Ergon Asphalt & Emulsions, Inc. and Suncor Energy USA each accounted for at least 10% but not more than 30% of asphalt services revenue in 2011. The loss of any of these customers could have a material adverse effect on our business, cash flows and results of operations. No other customer accounted for more than 10% of our asphalt services revenue during 2011.

Competition

We are subject to competition from other crude oil gathering, transportation, terminalling and storage operations that may be able to supply our customers with the same or comparable services on a more competitive basis. We compete with national, regional and local gathering, storage and pipeline companies and liquid asphalt cement storage and processing companies, including the major integrated oil companies, of widely varying sizes, financial resources and experience.

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With respect to our crude oil gathering and transportation services, these competitors include Enterprise Products Partners L.P., Plains All American Pipeline, L.P., ConocoPhillips, and Sunoco Logistics Partners L.P., among others. With respect to our crude oil storage and terminalling services, these competitors include Magellan Midstream Partners, L.P., Enbridge Energy Partners, L.P. and Plains All American Pipeline, L.P, among others. Several of our competitors conduct portions of their operations through publicly traded partnerships with structures similar to ours, including Plains All American Pipeline, L.P., Enterprise Products Partners L.P., Sunoco Logistics Partners L.P, Rose Rock Midstream L.P, and Magellan Midstream Partners, L.P. Our ability to compete could be harmed by factors we cannot control, including:

- the perception that another company can provide better service;
- our prior association with SemCorp and any negative goodwill created by SemCorp's bankruptcy filings;
- the availability of crude oil alternative supply points, or crude oil supply points located closer to the operations of our customers; and
- a decision by our competitors to acquire or construct crude oil midstream assets and provide gathering, transportation, terminalling or storage services in geographic areas, or to customers, served by our assets and services.

The asphalt industry is highly fragmented and regional in nature. Participants range in size from major oil companies to small family-owned proprietorships. Participants in the asphalt business include refiners such as BP p.l.c., Flint Hills Resources, L.P., CHS, Inc., Exxon Mobil Corporation, ConocoPhillips Company, NuStar Energy L.P., Ergon, Inc., Marathon Petroleum Company LLC, Alon USA LP, Suncor Energy Inc. and Valero Energy Corporation; resellers such as NuStar Energy L.P., Idaho Asphalt Supply, Inc. and Asphalt Materials, Inc.; and large road construction firms such as OldCastle Materials, Inc., and Colas SA. We compete for asphalt services with the noted national, regional and local industry participants as well as liquid asphalt cement terminalling and storage companies including the major integrated oil companies and a variety of others including KinderMorgan Energy Partners, International-Matex Tank Terminals and Houston Fuel Oil Terminal Company.

If we are unable to compete with services offered by other midstream enterprises, our ability to make distributions to our unitholders may be adversely affected. Additionally, we also compete with national, regional and local companies for asset acquisitions and expansion opportunities. Some of these competitors are substantially larger than us and have greater financial resources and lower costs of capital than we do.

Interstate Pipeline Regulation

Currently, we have one tariff rate on the Longview System that is regulated by Federal Energy Regulatory Commission, or FERC, and other tariff rates that are regulated by the Texas Railroad Commission.

Longview System. FERC, pursuant to the Interstate Commerce Act of 1887, or ICA, as amended, the Energy Policy Act of 1992 ("Energy Policy Act"), and rules and orders promulgated thereunder, regulates the tariff rates for our Longview system. The FERC requires that interstate oil pipelines file tariffs that contain rules and regulations governing the rates and charges for services performed. These tariffs apply to the interstate movement of crude and liquid petroleum products. Pursuant to the ICA, the rates, terms and conditions for providing service on ICA-regulated pipelines must be just and reasonable, and the service must be provided on a non-discriminatory basis. The ICA permits interested persons to challenge proposed new or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

Our FERC regulated rate is deemed just and reasonable, or grandfathered, under the Energy Policy Act. The Energy Policy Act limits the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party would have to show that it was previously contractually barred from challenging the rates, or that the economic circumstances of the liquids pipeline that were a basis for the rate or the nature of the service underlying the rate had substantially changed or that the rate was unduly discriminatory or preferential.

We cannot predict what rates we will be allowed to charge in the future for service on FERC regulated systems. Because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Gathering and Intrastate Pipeline Regulation. All intrastate pipelines in the state of Texas are regulated by the Texas Railroad Commission and in Oklahoma are regulated by the Oklahoma Corporation Commission. In the states in which we operate, regulation of crude gathering facilities and intrastate crude pipeline facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. For example, our intrastate crude pipeline facilities in Texas must have a tariff on file and charge just and reasonable rates for service, which must be provided on a non-discriminatory basis. Although state regulation is typically less onerous than at FERC, proposed and existing rates subject to state regulation and the provision of non-discriminatory service are subject to challenge by complaint.

Pipeline Safety. Our pipelines are subject to state and federal laws and regulations governing design, construction, operation, and maintenance of the lines; qualifications of pipeline personnel; public awareness; emergency response and other aspects of pipeline safety. These laws and regulations are subject to change, resulting in potentially more stringent requirements and increased costs. Applicable pipeline safety regulations establish minimum safety requirements and, for pipelines that pose a greater risk to populated areas or environmentally sensitive areas, impose a more rigorous requirement for the implementation of pipeline integrity management programs for our pipelines. In 2006, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or PIPES, reauthorized and amended the Department of Transportation's, or DOT's, pipeline safety programs. Included in PIPES is a provision eliminating the regulatory exemption contained in Part 195 for hazardous liquid pipelines operated at low stress. Final rules under PIPES were promulgated in July 2008 and extend all existing safety regulations, including integrity management requirements, to large-diameter low-stress pipelines within a defined "buffer" area around an "unusually sensitive area," which include areas that contain sole-source drinking water, endangered species, or other ecological resources. Operators of these, and all other low-stress pipelines, are required by the rules to comply with annual reporting requirements. On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The Act increases the maximum civil penalties for pipeline safety administrative enforcement actions; requires the DOT to study and report on the expansion of integrity management requirements, the sufficiency of existing gathering line regulations to ensure safety, and the feasibility of leak detection systems for hazardous liquid pipelines; requires pipeline operators to verify their records on maximum allowable operating pressure; and imposes new emergency response and incident notification requirements. Both states in which we operate pipelines, Oklahoma and Texas, incorporate into their state rules those federal safety standards for hazardous liquids pipelines contained in Title 40, Part 195 of the Federal Code of Regulations. As a result, the issuance of any new pipeline safety regulations, including additional requirements for integrity management, are likely to increase the operating costs of our pipelines subject to such new requirements, and such future costs may be material.

Trucking Regulation. We operate a fleet of trucks to transport crude oil and oilfield materials as a private, contract and common carrier. We are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, maintaining log books, truck manifest preparations, the placement of safety placards on the trucks and trailer vehicles, drug and alcohol testing, safety of operation and equipment, and many other aspects of truck operations. We are also subject to requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, with respect to our trucking operations.

Environmental, Health and Safety Risks

General. Our midstream crude oil gathering, transportation, terminalling and storage operations, together with our asphalt assets, are subject to stringent federal, state, and local laws and regulations relating to the discharge of materials into the environment or otherwise relating to protection of the environment. As with the midstream and liquid asphalt cement industries generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of significant administrative, civil and criminal penalties, the imposition of investigatory and remedial liabilities, and even the issuance of injunctions that may restrict or prohibit some or all of our operations. We believe that our operations are in substantial compliance with applicable laws and regulations. However, environmental laws and regulations are subject to change, resulting in potentially more stringent requirements, and we cannot provide any assurance that the cost of compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings.

There are also risks of accidental releases into the environment inherent in the nature of both our midstream and liquid asphalt cement operations, such as leaks or spills of petroleum products or hazardous materials from our pipelines, trucks, terminals and storage facilities. A discharge of petroleum products or hazardous materials into the environment could, to the extent such event is not covered by insurance, subject us to substantial expense, including costs related to environmental clean-up or restoration, compliance with applicable laws and regulations, and any personal injury, natural resource or property damage claims made by neighboring landowners and other third parties.

The following is a summary of the more significant current environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may require material capital expenditures or have a material adverse impact on our results of operations, financial position and cash flows.

Water. The federal Clean Water Act and analogous state and local laws impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States and state waters. Permits must be obtained to discharge pollutants into these waters. The Clean Water Act and analogous laws provide significant penalties for unauthorized discharges and impose substantial potential liabilities for cleaning up spills and leaks into water. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in substantial compliance with any such applicable state requirements.

The federal Oil Pollution Act, as amended, or OPA, was enacted in 1990 and amends provisions of the Federal Water Pollution Control Act of 1972, the Clean Water Act, and other statutes as they pertain to prevention and response to oil spills. The OPA, and analogous state and local laws, subject owners of facilities used for storing, handling or transporting oil, including trucks and pipelines, to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the United States. The OPA, the Clean Water Act and other analogous laws also impose certain spill prevention, control and countermeasure requirements, such as the preparation of detailed oil spill emergency response plans and the construction of dikes and other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or leak. We believe that we are in substantial compliance with applicable OPA and analogous state and local requirements.

Air Emissions. Our operations are subject to the federal Clean Air Act ("CAA"), as amended, as well as to comparable state and local laws. We believe that our operations are in substantial compliance with these laws in those areas in which we operate. Amendments to the federal Clean Air Act enacted in 1990 imposed a federal operating permit requirement for major sources of air emissions. Our crude oil terminal located in Cushing, Oklahoma holds such a permit, which is referred to as a "Title V permit." In 2010, the EPA entered into a settlement requiring it to reevaluate regulations for the control of air emissions from the oil and natural gas industry. As a result, the EPA proposed regulations in July 2011 that would establish new air pollution standards for the oil and natural gas industry, including new source performance standards for volatile organic compounds and sulfur dioxide and an air toxics standards for oil and natural gas production and for natural gas transmission and storage. These proposed rules are currently pending adoption. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with obtaining or maintaining permits and approvals addressing air emission related issues. Although we can provide no assurance, we believe future compliance with the federal Clean Air Act, as amended, will not have a material adverse effect on our financial condition, results of operations or cash flows.

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Climate Change. Legislative and regulatory measures to address concerns that emissions of certain gases, commonly referred to as “greenhouse gases” (“GHGs”), may be contributing to warming of the Earth’s atmosphere are in various phases of discussions or implementation at the international, national, regional, and state levels. The oil and gas industry is a direct source of certain GHG emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. In the United States, federal legislation requiring GHG controls is under consideration. In addition, the Environmental Protection Agency (the "EPA") has promulgated a series of rulemakings and other actions intended to result in the regulation of GHGs as pollutants under the CAA. In April 2010, EPA promulgated final motor vehicle GHG emission standards, which apply to vehicle model years 2012 - 2016. EPA has taken the position that the motor vehicle GHG emission standards triggered CAA permitting requirements for certain affected stationary sources of GHG emissions beginning on January 2, 2011. In May 2010, EPA finalized the Prevention of Significant Deterioration and Title V GHG Tailoring Rule, which phases in federal new source review and Title V permitting requirements for certain affected stationary sources of GHG emissions, beginning January 2, 2011. These EPA rulemakings could affect our operations and ability to obtain air permits for new or modified facilities. Furthermore, in 2009, the EPA issued a “Mandatory Reporting of Greenhouse Gases” final rule, establishing a comprehensive scheme of regulations that require monitoring and reporting of GHG emissions on an annual basis by operators of stationary sources in the U.S. emitting more than established annual thresholds of carbon dioxide-equivalent GHG emissions. Monitoring obligations began in 2010. The first emissions reports required under the new rule were due on or before March 31, 2011, and the scope of the rule was expanded for 2011 to cover additional petroleum and natural gas production, processing, and transmission sources that were not previously covered by the rule. Although this new rule does not control GHG emission levels from any facilities, it has caused us to incur monitoring and reporting costs.

Legislation and regulations relating to control or reporting of GHG emissions are also in various stages of discussions or implementation in many of the states in which we operate. Passage of climate change legislation or other federal or state legislative or regulatory initiatives that regulate or restrict GHG emissions in areas in which we conduct business could adversely affect the demand for our products and services, and depending on the particular program adopted could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions (e.g., from natural gas fired combustion units), pay any taxes related to our GHG emissions and/or administer and manage a GHG emissions program. At this time, it is not possible to accurately estimate how laws or regulations addressing GHG emissions would impact our business. Although we would not be impacted to a greater degree than other similarly situated midstream transporters of petroleum products, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the products we transport.

In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns. An increase in severe weather patterns could result in damages to or loss of our physical assets, impact our ability to conduct operations and/or result in a disruption of our customer’s operations. These types of physical changes could also affect entities that provide goods and services to us and indirectly have an adverse affect on our business as a result of increases in costs or availability of goods and services. Changes of this nature could have a material adverse impact on our business.

Solid Waste Disposal and Environmental Remediation. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as Superfund, as well as comparable state and local laws, impose liability without regard to fault or the legality of the original act, on certain classes of persons associated with the release of a “hazardous substance” into the environment. These persons include the owner or operator of the site or sites where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Under CERCLA, such persons may be subject to strict and, under certain circumstances, joint and several liability for cleanup costs, for damages to natural resources, and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by releases of hazardous substances or other pollutants. We generate materials in the course of our operations that are regulated as hazardous substances. Beyond the federal statute, many states have enacted environmental response statutes that are analogous to CERCLA.

We generate wastes, including "hazardous wastes," that are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended, or RCRA, as well as to comparable state and local laws. While normal costs of complying with RCRA would not be expected to have a material adverse effect on our financial conditions, we could incur substantial expense in the future if the RCRA exclusion for oil and gas waste were eliminated. Should our oil and gas wastes become subject to RCRA, we would also become subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses for us.

We currently own or lease properties where hazardous substances are being handled or have been handled for many years. Although we believe that operating and disposal practices that were standard in the midstream and liquid asphalt cement industries at the time were utilized at properties leased or owned by us, historical releases of hazardous substances or associated generated wastes have occurred on or under the properties owned or leased by us, or on or under other locations where these wastes were taken for disposal. In addition, many of these properties have been operated in the past by third parties whose treatment and disposal or release of hazardous substances or associated generated wastes were not under our control. These properties and the materials disposed on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously spilled hazardous materials or associated generated wastes (including wastes disposed of or released by other site occupants or by prior owners or operators), or to clean up contaminated property (including contaminated groundwater).

Contamination resulting from the release of hazardous substances or associated generated wastes is not unusual within the midstream and liquid asphalt cement industries. Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. In the future, we likely will experience releases of hazardous materials, including petroleum products, into the environment from our pipeline terminalling and storage operations, or discover releases that were previously unidentified. Although we maintain a program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to environmental releases from our assets may substantially affect our business.

OSHA.   We are subject to the requirements of OSHA, as well as to comparable state and local laws that regulate the protection of worker health and safety. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general midstream and liquid asphalt cement industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

Anti-Terrorism Measures.   The federal Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS issued an interim final rule in April 2007 known as the Chemical Facility Anti-Terrorism Standards ("CFATS") regarding risk-based performance standards to be attained pursuant to the act and, on November 20, 2007, further issued an Appendix A to CFATS that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. We currently do not handle, use, store, or process any "Chemicals of Interest" ("COI") listed in Appendix A above their respective threshold quantities, and are therefore not subject to requirements of CFATS. We will continue to monitor the CFATS for regulatory changes that could impact our operations in the future.

Operational Hazards and Insurance

Pipelines, terminals, storage tanks, and similar facilities may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties, including coverage for pollution related events. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities. Notwithstanding what we believe is a favorable claims history, the overall cost of the insurance program as well as the deductibles and overall retention levels that we maintain have increased. Through the utilization of deductibles and retentions we self insure the “working layer” of loss activity to create a more efficient and cost effective program. The working layer consists of high frequency/low severity losses that are best retained and managed in-house. As we continue to grow, we will continue to monitor our retentions as they relate to the overall cost and scope of our insurance program.

Employees

As of December 31, 2011, we employed approximately 500 persons. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with these employees are satisfactory.

Mr. James C. Dyer, our Chief Executive Officer and a director, is also an officer of Vitol Inc. Certain of our employees provided services to Vitol pursuant to an Omnibus Agreement between us and Vitol Inc., effective as of January 1, 2010 (the “Vitol Omnibus Agreement”). As of January 1, 2012, none of our employees are providing services to Vitol pursuant to the Vitol Omnibus Agreement. For more information regarding the Vitol Omnibus Agreement, please see “Item 13—Certain Relationships and Related Party Transactions, and Director Independence—Agreements with Vitol.”

Financial Information about Segments

Information regarding our operating revenues, profit and loss and identifiable assets attributable to each of our segments is presented in Note 18 to our consolidated financial statements included in this annual report on Form 10-K.

Available Information

We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports filed with the SEC under the Securities and Exchange Act of 1934. These documents may be accessed free of charge on our website, www.bkep.com, as soon as is reasonably practicable after their filing with the SEC. Information contained on our website is not incorporated by reference in this report or any of our other filings. 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. Information on the operation of the Public Reference Room is available by calling 1-800-SEC-0330. The SEC also maintains a website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The SEC’s website is www.sec.gov.

Item 1A. Risk Factors.

Limited partner interests are inherently different from the 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 a similar business. You should carefully consider the following risk factors together with all of the other information included in this report. If any of the following risks were actually to occur, our business, financial condition, results of operations and cash flows could be materially adversely affected. In that case, we might not be able to pay distributions on our units, the trading price of our units could decline and our unitholders could lose all or part of their investment.

Risks Related to our Business

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

In order to make cash distributions on our Preferred Units at the preference distribution rate of $0.17875 per unit per quarter, or $0.715 per unit per year, and on our common units at the minimum quarterly distribution of $0.11 per unit per quarter, or $0.44 per unit per year, we will require available cash of approximately $8.1 million per quarter, or $32.3 million per year. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions on our Preferred Units at the preference rate or on our common units at the minimum quarterly 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 risks described herein.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level of capital expenditures we make;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our credit facility or other debt agreements; and
- the amount of cash reserves established by our General Partner.

Our cash available for distributions to our unitholders could be negatively impacted if we are unable to extend existing storage contracts or enter into new storage contracts at our Cushing terminal.

We have a total of 6.6 million barrels of storage capacity at the Cushing terminal. Customer storage contracts for all but 2.1 million barrels of storage at this location have expired (and are operating on a month-to-month basis) or expire in 2012. We may not be able to extend, renegotiate or replace these contracts when they expire, and the terms of any renegotiated contracts may not be as favorable as the contracts they replace. In addition, to the degree that we operate outside of long-term contracts, our revenues can be significantly more volatile than would be the case with a pricing structure negotiated through a long-term storage contract. If we cannot successfully renew significant contracts or must renew them on less favorable terms, our revenues from these arrangements could decline which could have a material adverse effect on our financial condition, results of operations and cash flows.

We depend on certain key customers for a portion of our revenues and are exposed to credit risks of these customers. The loss of or material nonpayment or nonperformance by any of these key customers could adversely affect our cash flow and results of operations.

We rely on certain key customers for a portion of revenues. For example, Vitol represented approximately $27.6 million or 71% of our total crude oil terminalling and storage revenue, $4.8 million or 22% of our crude oil pipeline services revenue, and $11.5 million or 21% of total crude oil trucking and producer field services revenue in 2011. Vitol is a private company and we have limited information regarding its financial condition. In addition, Mercuria Energy Trading, Inc. accounted for at least 15% but not more than 25% of crude oil terminalling and storage services revenue in 2011. ExxonMobil Corporation and Valero Marketing & Supply Co each accounted for at least 10% but not more than 20% of crude oil pipeline services revenue in 2011. MV Purchasing, LLC accounted for at least 10% but not more than 20% of crude oil trucking and producer field services revenue in 2011. NuStar Marketing LLC, Ergon Asphalt & Emulsions, Inc. and Suncor Energy USA each accounted for at least 10% but not more than 30% of asphalt services revenue in 2011. Ergon Asphalt & Emulsions, Inc. and Vitol comprised 22% and 32%, respectively, of total accounts receivable at December 31, 2011.

We may be unable to negotiate extensions or replacements of contracts with key customers on favorable terms. In addition, some of these key customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. Additionally, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. The loss of all or even a portion of the contracted volumes of these key customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

We are exposed to the credit risks of our third-party customers in the ordinary course of our gathering activities. Any material nonpayment or nonperformance by our third-party customers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our third-party customers. Some of our customers may be highly leveraged and subject to their own operating and regulatory risks. In addition, any material nonpayment or nonperformance by our customers could require us to pursue substitute customers for our affected assets or provide alternative services. Any such efforts may not be successful or may not provide similar fees. These events could have a material adverse effect on our financial condition and results of operations.

The amount of cash we have available for distribution to holders of our units depends primarily on our cash flow and not solely on earnings reflected in our financial statements. Consequently, even if we are profitable and are otherwise able to pay distributions, we may not be able to make cash distributions to holders of our units.

Our unitholders should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and not solely on earnings reflected in our financial statements, which will be affected by non-cash items. As a result, we may make cash distributions, if permitted by our credit agreement, 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.

Our debt levels under our credit agreement may limit our ability to make distributions and our flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2011, we had approximately $218 million in outstanding indebtedness under our credit facility. Our level of debt under the credit facility could have important consequences for us, including the following:

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

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

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

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

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

We may not be able to raise sufficient capital to grow our business.

As of March 9, 2012, we had an aggregate unused credit availability under our revolving credit facility of approximately $77.3 million and cash on hand of approximately $4.6 million. Our ability to access capital markets may be limited due to uncertainty of our future cash flows, litigation and other contingencies. In addition, we may have difficulty obtaining a credit rating or any credit rating that we do obtain may be lower than it otherwise would be due to these uncertainties. The lack of a credit rating or a low credit rating may also adversely impact our ability to access capital markets.

Weak economic conditions and the volatility and disruption in the financial markets could increase the cost of raising money in the debt and equity capital markets substantially while diminishing the availability of funds from those markets. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers.

If we fail to raise additional capital or an event of default exists under our credit agreement, we may be forced to sell assets or take other action that could have a material adverse effect on our business, the price of our units and our results of operations. In addition, if we are unable to access the capital markets for acquisitions or expansion projects, it may have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

If we borrow funds to make any permitted quarterly distributions, our ability to pursue acquisitions and other business opportunities may be limited and our operations may be materially and adversely affected.

Available cash for the purpose of making distributions to unitholders includes working capital borrowings. If we borrow funds to pay one or more quarterly distributions, such amounts will incur interest and must be repaid in accordance with the terms of our credit facility. In addition, any amounts borrowed for permitted distributions to our unitholders will reduce the funds available to us for other purposes under our credit facility, including amounts available for use in connection with acquisitions and other business opportunities. If we are unable to pursue our growth strategy due to our limited ability to borrow funds, our operations may be materially and adversely affected.

We are indirectly exposed to commodity price volatility.

Our operations have minimal direct exposure to changes in crude oil and asphalt cement prices. However, the volumes of crude oil and asphalt cement we gather, transport, terminal or store are indirectly affected by commodity prices because many of our customers have direct commodity price exposure. If our customers are negatively impacted by commodity price volatility, they may, among other items, decrease the amount of services that we provide to them. The prices of crude oil and asphalt are inherently volatile, and we expect this volatility to continue. Any significant reduction in the amount of services we provide to our customers would have a material adverse effect on our results of operations and cash flows.

Our revenues from third-party customers are generated under contracts that must be renegotiated periodically and that allow the customer to reduce or suspend performance in some circumstances, which could cause our revenues from those contracts to decline and reduce our ability to make distributions to our unitholders.

Some of our contract-based revenues from customers are generated under contracts with terms which allow the customer to reduce or suspend performance under the contract in specified circumstances, such as the occurrence of a catastrophic event to our or the customer's operations. The occurrence of an event which results in a material reduction or suspension of our customer's performance could have a material adverse effect on our financial condition, results of operations and cash flows.

Many of our contracts with customers for producer field services have terms of one year or less. As these contracts expire, they must be extended and renegotiated or replaced. We may not be able to extend, renegotiate or replace these contracts when they expire, and the terms of any renegotiated contracts may not be as favorable as the contracts they replace. In particular, our ability to extend or replace contracts could be harmed by numerous competitive factors, such as those described above under "Item 1. Business — Competition." We face intense competition in our gathering, transportation, terminalling and storage activities. Competition from other providers of crude oil gathering, transportation, terminalling and storage services that are able to supply our customers with those services at a lower price could reduce our ability to make distributions to our unitholders. Additionally, we may incur substantial costs if modifications to our terminals are required in order to attract substitute customers or provide alternative services. If we cannot successfully renew significant contracts or must renew them on less favorable terms, or if we incur substantial costs in modifying our terminals, our revenues from these arrangements could decline which could have a material adverse effect on our financial condition, results of operations and cash flows.

Certain of our asphalt services contracts have short terms and certain leases relating to our asphalt operations may be terminated upon short notice.

We currently have leases and storage agreements with third party customers relating to 43 of our 44 asphalt facilities. The lease and storage agreements with third parties have terms that terminate between December 31, 2012 and October 31, 2017. We may not be able to renew or extend our existing contracts or enter into new leases or storage agreements when such contracts expire. In addition, certain key customers account for a portion of our asphalt services revenues, the loss of which could result in a decrease in revenues from our asphalt operations. A significant decrease in the revenues we receive from our asphalt operations could result in violations of covenants under our credit facility and could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

In addition, certain of our asphalt facilities are located on land that we lease. Some of these leases may be terminated by the lessor with as short as thirty days' notice. We also have not yet received consent from certain of the lessors to sublease such facilities, which may result in a default under such lease or invalidate the subleases. If such leases were terminated, it could have a material adverse effect on our ability to provide asphalt services, which could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business. In addition, in certain instances, we have not entered into new leases with a lessor although we continue to use prior leases and make payments to the lessor and are in the process of negotiating new leases. If it were determined that we did not have rights under these leases, it could have a material adverse effect on our ability to conduct our asphalt operations and on our financial condition, results of operations and cash flows.

We are not fully insured against all risks incident to our business, and could incur substantial liabilities as a result.

We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of changing market conditions, premiums and deductibles for certain of our insurance policies may increase substantially in the future. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

A significant decrease in demand for crude oil and/or finished asphalt products in the areas served by our storage facilities and pipelines could reduce our ability to make distributions to our unitholders.

A sustained decrease in demand for crude oil and/or finished asphalt products in the areas served by our storage facilities and pipelines could significantly reduce our revenues and, therefore, reduce our ability to make or increase distributions to our unitholders. Factors that could lead to a decrease in market demand for crude oil and finished asphalt products include:

- lower demand by consumers for refined products, including finished asphalt products, as a result of recession or other adverse economic conditions or due to high prices caused by an increase in the market price of crude oil or higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasolines or other refined products;

- a shift by consumers to more fuel-efficient or alternative fuel vehicles or an increase in fuel economy of vehicles, whether as a result of technological advances by manufacturers, governmental or regulatory actions or otherwise; and

- fluctuations in demand for crude oil, such as those caused by refinery downtime or shutdowns, could also significantly reduce our revenues and, therefore, reduce our ability to make distributions to our unitholders.

Certain of our field and pipeline operating costs and expenses are fixed and do not vary with the volumes we gather and transport. These costs and expenses may not decrease ratably or at all should we experience a reduction in our volumes gathered or transmitted by our gathering and transportation operations. As a result, we may experience declines in our margin and profitability if our volumes decrease.

A material decrease in the production of crude oil from the oil fields served by our pipelines could materially reduce our ability to make distributions to our unitholders.

The throughput on our crude oil pipelines depends on the availability of attractively priced crude oil produced from the oil fields served by such pipelines, or through connections with pipelines owned by third parties. Crude oil production may decline for a number of reasons, including natural declines due to depleting wells, a material decrease in the price of crude oil, or the inability of producers to obtain necessary drilling or other permits from applicable governmental authorities. If we are unable to replace volumes lost due to a temporary or permanent material decrease in production from the oil fields served by our crude oil pipelines, our throughput could decline, reducing our revenue and cash flow and adversely affecting our financial condition and results of operations. In addition, it is difficult to attract producers to a new gathering system if the producer is already connected to an existing system. As a result, third-party shippers on our pipeline systems may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil.

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A material decrease in the production of liquid asphalt cement could materially reduce our ability to make distributions to our unitholders.

The throughput at our asphalt facilities depends on the availability of attractively priced liquid asphalt cement produced from the various liquid asphalt cement producing refineries. Liquid asphalt cement production may decline for a number of reasons, including refiners processing more light, sweet crude oil or refiners installing coker units that further refine heavy residual fuel oil bottoms such as liquid asphalt cement. If our customers are unable to replace volumes lost due to a temporary or permanent material decrease in production from the suppliers of liquid asphalt cement, our throughput could decline, reducing our revenue and cash flow and adversely affecting our financial condition and results of operations.

We face intense competition in our gathering, transportation, terminalling and storage activities. Competition from other providers of crude oil gathering, transportation, terminalling and storage services that are able to supply our customers with those services at a lower price could reduce our ability to make distributions to our unitholders.

We are subject to competition from other crude oil gathering, transportation, terminalling and storage operations that may be able to supply our customers with the same or comparable services on a more competitive basis. We compete with national, regional and local gathering, storage, terminalling and pipeline companies, including the major integrated oil companies, of widely varying sizes, financial resources and experience. Some of these competitors are substantially larger than us, have greater financial resources, and control substantially greater storage capacity than we do. With respect to our gathering and transportation services, these competitors include Enterprise Products Partners L.P., Plains All American Pipeline, L.P., ConocoPhillips, and Sunoco Logistics Partners L.P., among others. With respect to our storage and terminalling services, these competitors include Magellan Midstream Partners, L.P., Enbridge Energy Partners, L.P., Enterprise Products Partners L.P. and Plains All American Pipeline, L.P. Several of our competitors conduct portions of their operations through publicly traded partnerships with structures similar to ours, including Plains All American Pipeline, L.P., Enterprise Products Partners L.P., Sunoco Logistics Partners L.P. and Enbridge Energy Partners, L.P. Our ability to compete could be harmed by numerous factors, including:

- price competition;
- the perception that another company can provide better service;
- losses sustained by our customers as a result of SemCorp having filed bankruptcy; and
- the availability of alternative supply points, or supply points located closer to the operations of our customers.

In addition, each of Charlesbank and Vitol owns midstream assets and may engage in competition with us. If we are unable to compete with services offered by other midstream enterprises, it could have a material adverse effect on our financial condition, results of operations and cash flows. See "— Risks Inherent in an Investment in Us — Vitol and Charlesbank may compete with us, which could adversely affect our existing business and limit our ability to acquire additional assets or businesses."

Some of our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets.

Some of our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets. Reduced throughput on these interconnecting pipelines as a result of testing, line repair, reduced operating pressures or other causes could result in reduced throughput on our pipeline systems that would adversely affect our revenue, cash flow and results of operations.

If we are unable to make acquisitions on economically acceptable terms, our future growth may be limited.

Our ability to grow in the future will depend, in part, on our ability to make acquisitions that result in an increase in the cash generated per unit from operations. Vitol and Charlesbank have indicated that they intend to use us as a growth vehicle to pursue the acquisition and expansion of midstream energy businesses and assets. Vitol and Charlesbank have formed Development Company and have informed us it is intended to be focused on developing projects that we may later have the opportunity to acquire. Vitol and Charlesbank own Development Company and we have no interest in this new entity. We cannot say with any certainty if Development Company will develop any projects or, if it does, which, if any, of these future acquisition opportunities may be made available to us by Development Company or if we will choose to pursue any such opportunity. In addition, indentifying projects for and developing projects within Development Company may result in the diversion of management's and employees' attention from operating our assets and other business concerns of our partnership.

In addition to any projects acquired and developed by Development Company, we may also make acquisitions directly from third parties. If we are unable to make accretive acquisitions, either because we are (1) unable to establish the terms of Development Company or acquire projects from Development Company when they are available, (2) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (3) unable to obtain financing for these acquisitions on economically acceptable terms or (4) outbid by competitors, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations per unit.

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

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

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our 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.

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If we acquire assets that are distinct and separate from our existing terminalling, storage, gathering and transportation operations, it could subject us to additional business and operating risks.

We may acquire midstream assets that have operations in new and distinct lines of business from our crude oil or our liquid asphalt cement operations. Integration of a new business is a complex, costly and time-consuming process. Failure to timely and successfully integrate acquired entities' new lines of business with our existing operations may have a material adverse effect on our business, financial condition, results of operations and cash flows. The difficulties of integrating a new business with our existing operations include, among other things:

- operating distinct businesses that require different operating strategies and different managerial expertise;
- the necessity of coordinating organizations, systems and facilities in different locations;
- integrating personnel with diverse business backgrounds and organizational cultures; and
- consolidating corporate and administrative functions.

In addition, the diversion of our attention and any delays or difficulties encountered in connection with the integration of a new business, such as unanticipated liabilities or costs, could harm our existing business, results of operations, financial conditions and prospects. Furthermore, new lines of business will subject us to additional business and operating risks. For example, we may in the future determine to acquire businesses that are subject to significant risks due to fluctuations in commodity prices. These new business and operating risks could have a material adverse effect on our financial condition, results of operations and cash flows.

Expanding our business by constructing new assets subjects us to risks that projects may not be completed on schedule, and that the costs associated with projects may exceed our expectations, which could cause our cash available for distribution to our unitholders to be less than anticipated.

The construction of additions or modifications to our existing assets, and the construction of new assets, involves numerous regulatory, environmental, political, legal and operational uncertainties and requires the expenditure of significant amounts of capital. If we undertake these types of projects, they may not be completed on schedule or at all or at the budgeted cost. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. Moreover, we may construct facilities to capture anticipated future growth in demand in a market in which such growth does not materialize.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any necessary pipeline repair, or preventative or remedial measures, which could have a material adverse effect on our results of operations.

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," including high population areas, areas that are sources of drinking water or ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;

- identify and characterize 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.

Effective July, 2008, the DOT broadened the scope of coverage of its existing pipeline safety standards, including its integrity management programs, to include certain rural onshore hazardous liquid and low-stress pipeline systems found near "unusually sensitive areas," including non-populated areas requiring extra protection because of the presence of sole source drinking water resources, endangered species, or other ecological resources. Also, in December, 2006, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 was enacted. This act reauthorizes and amends the DOT's pipeline safety programs and includes a provision eliminating the regulatory exemption for hazardous liquid pipelines operated at low stress. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, enacted in December, 2011, requires the DOT to study and report on the expansion of integrity management requirements, the sufficiency of existing gathering line regulations to ensure safety, and the feasibility of leak detection systems for hazardous liquid pipelines. Adoption of new or more stringent pipeline safety regulations affecting our interstate gathering or low-stress pipelines could result in more rigorous and costly integrity management planning requirements being imposed on those lines, which could have a material adverse effect on our results of operations. Please read "Item 1. Business—Regulation—Pipeline Safety" for more information.

We may be subject to significant costs related to environmental investigations and/or remediation activities at our asphalt facilities.

We acquired our asphalt assets from SemCorp in 2008 and 2009. The majority of these assets were previously acquired by SemCorp from a large privately-owned company ("Seller") in 2005. Seller retained certain liabilities, including certain environmental liabilities, when it sold the assets to SemCorp. Since 2005, Seller has been conducting environmental investigation and/or remediation activities at certain of our asphalt facilities in connection with these retained environmental liabilities. Seller has alleged that it does not have continued responsibility for these retained environmental liabilities at one of our asphalt facilities because of SemCorp's bankruptcy. Because Seller has conducted all environmental investigation and/or remediation activities at this site, we do not know the extent of any environmental issues and we are unable to estimate the costs or timing of any investigation and/or remediation activities, which may be material. In addition, Seller may make similar allegations regarding retained environmental liabilities at other of our asphalt facilities. Although we intend to defend any such allegations, if we are found to be liable for such environmental liabilities, it could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

Our operations are subject to environmental and worker safety laws and regulations that may expose us to significant costs and liabilities. Failure to comply with these laws and regulations could adversely affect our ability to make distributions to our unitholders.

Our midstream crude oil gathering, transportation, terminalling and storage operations and our asphalt terminalling and storage assets, are subject to stringent federal, state and local laws and regulations relating to the protection of the environment. Various governmental authorities, including the EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several strict liability may be incurred without regard to fault or the legality of the original conduct under CERCLA, RCRA and analogous state laws for the remediation of contaminated areas. Private parties, including the owners of properties located near our terminalling and storage facilities or through which our pipeline systems pass, also may have the right to pursue legal actions to enforce compliance, as well as seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. Moreover, new stricter laws, regulations or enforcement policies could be implemented that significantly increase our compliance costs and the cost of any remediation that may become necessary, some of which may be material.

In performing midstream operations and asphalt services, we incur environmental costs and liabilities in connection with the handling of hydrocarbons and solid wastes. We currently own, operate or lease properties that for many years have been used for midstream activities, including properties in and around the Cushing Interchange, and with respect to our asphalt assets, for asphalt activities. Activities by us or prior owners, lessees or users of these properties over whom we had no control may have resulted in the spill or release of hydrocarbons or solid wastes on or under them. Additionally, some sites we own or operate are located near current or former storage, terminal and pipeline operations, and there is a risk that contamination has migrated from those sites to ours. Increasingly strict environmental laws, regulations and enforcement policies as well as claims for damages and other similar developments could result in significant costs and liabilities, and our ability to make distributions to our unitholders could suffer as a result. Please see “Item 1—Business—Regulation” for more information.

In addition, the workplaces associated with the storage facilities and pipelines we operate are subject to OSHA requirements and comparable state statutes that regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local government authorities, and local residents. Failure to comply with OSHA requirements, including general industry standards, recordkeeping requirements and monitoring of occupational exposure to regulated substances, could subject us to fines or significant compliance costs and have a material adverse effect on our financial condition, results of operations and cash flows.

Adoption of legislation and regulatory measures targeting greenhouse gas (GHG) emissions could affect our operations, expose us to significant costs and liabilities, and reduce demand for the products we transport.

The crude oil and petroleum-based product business is a direct source of certain GHG emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Federal legislation requiring GHG controls is under consideration and may be enacted. Moreover, EPA has promulgated a series of rulemakings and other actions intended to result in the regulation of GHGs as pollutants under the CAA. In April 2010, EPA promulgated final motor vehicle GHG emission standards, which apply to vehicle model years 2012 - 2016. EPA has taken the position that the motor vehicle GHG emission standards triggered CAA permitting requirements for certain affected stationary sources of GHG emissions beginning on January 2, 2011. In May 2010, EPA finalized the Prevention of Significant Deterioration and Title V GHG Tailoring Rule, which phases in federal new source review and Title V permitting requirements for certain affected stationary sources of GHG emissions, beginning January 2, 2011. These EPA rulemakings could affect our operations by effectively reducing demand for motor fuels from crude oil and could affect our ability to obtain air permits for new or modified facilities. Moreover, in 2009, the EPA issued a rule that establishes comprehensive requirements for monitoring and reporting of GHG emissions on an annual basis by operators of certain stationary sources in the U.S. emitting more than established annual thresholds of carbon dioxide-equivalent GHG emissions. Monitoring obligations began in 2010 and reporting obligations began in March 2011. Some of our facilities include natural gas-fired combustion units that may become subject to the rule. These facilities will be required to annually calculate their GHG emissions to determine whether they trigger reporting and monitoring requirements. To date, none of our facilities have exceeded the thresholds established for reporting or monitoring requirements. Although this rule does not control GHG emission levels from any facilities, it will still cause us to incur monitoring and reporting costs relating to GHG emissions. Furthermore, the scope of the rule was expanded for 2011 to cover additional petroleum and natural gas production, processing, and transmission sources (“Subpart W”) that were not previously covered by the rule. This expansion in scope may impact the crude oil industry and, as a result, affect our business. We are reviewing these Subpart W regulations to determine if our operations will trigger reporting requirements that come due in September 2012. Legislation and regulations relating to control or reporting of GHG emissions are also in various stages of discussions or implementation in many of the states in which we operate.

Passage of climate change legislation or other federal or state legislative or regulatory initiatives that regulate or restrict GHG emissions in areas in which we conduct business or that have the effect of requiring or encouraging reduced consumption or production of crude oil and petroleum-based products could potentially

- adversely affect the demand for our products and services;
- affect our operations and ability to obtain air permits for new or modified facilities;
- increase the costs to operate and maintain our facilities;

- increase the costs to install new emission controls on our facilities;
- increase the costs of our business by requiring us to acquire allowances to authorize our GHG emissions (e.g., for natural gas-fired combustion units);
- increase the costs of our business by requiring us to pay any taxes related to our GHG emissions and/or administer and manage a GHG emissions program; and
- increase the cost or availability of goods and services as a result of impacts on entities that provide goods and services to us.

In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns. A loss of coastline in the vicinity of our facilities or an increase in severe weather patterns could result in damages to or loss of our physical assets, impact our ability to conduct operations and/or result in a disruption of our customer's operations. These kinds of physical changes could also affect entities that provide goods and services to us and indirectly have an adverse affect on our business as a result of increases in costs or availability of goods and services. Changes of this nature could have a material adverse impact on our business.

Please read "Item 1. Business—Environmental, Health and Safety Risks—Climate" for more information.

Our business involves many hazards and operational risks, including adverse weather conditions, which could cause us to incur substantial liabilities.

Our operations are subject to the many hazards inherent in the transportation and storage of crude oil and the storage and processing of liquid asphalt cement, including:

- explosions, fires, accidents, including road and highway accidents involving our tanker trucks;
- extreme weather conditions, such as hurricanes which are common in the Gulf Coast and tornadoes and flooding which are common in the Midwest;
- damage to our pipelines, storage tanks, terminals and related equipment;
- leaks or releases of crude oil into the environment; and
- acts of terrorism or vandalism.

If any of these events were to occur, we could suffer substantial losses because of personal injury or loss of life, severe damage to and destruction of property and equipment, and pollution or other environmental damage resulting in curtailment or suspension of our related operations. In addition, mechanical malfunctions, faulty measurement or other errors may result in significant costs or lost revenues.

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

We do not own all of the land on which our pipelines and crude oil and asphalt facilities have been constructed, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way or any material real property leases lapse or terminate. We obtain the rights to construct and operate our pipelines and some of our crude oil and asphalt facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew leases, right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition, cash flows and our ability to make cash distributions to our unitholders. In addition, we are in the process of obtaining consents from the lessors for certain leased property that was transferred to us as part of the acquisition of our asphalt assets. If any consent is denied, it could have a material adverse effect on our business, results of operations, financial condition, cash flows and our ability to make cash distributions to our unitholders.

Risks Inherent in an Investment in Us

Vitol and Charlesbank control our General Partner, which has sole responsibility for conducting our business and managing our operations. Our General Partner has conflicts of interest with us and limited fiduciary duties, which may permit it to favor its own interests to the detriment of our unitholders.

Vitol and Charlesbank own and control our General Partner. Some of our General Partner's directors are directors and officers of Vitol or Charlesbank and our General Partner's Chief Executive Officer is affiliated with Vitol. Therefore, conflicts of interest may arise between our General Partner, on the one hand, and us and our unitholders, on the other hand. In resolving those conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. Although the conflicts committee of the Board may review such conflicts of interest, the Board is not required to submit such matters to the conflicts committee. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our General Partner, Vitol or Charlesbank to pursue a business strategy that favors us. Such persons may make these decisions in their best interest, 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 Vitol, Charlesbank and their affiliates, in resolving conflicts of interest;

- if we do not have sufficient available cash from operating surplus, our General Partner could cause us to use cash from non-operating sources, such as asset sales, issuances of securities and borrowings, to pay distributions, which means that we could make distributions that deteriorate our capital base and that our General Partner could receive distributions on its subordinated units and incentive distribution rights to which it would not otherwise be entitled if we did not have sufficient available cash from operating surplus to make such distributions;

- Vitol and Charlesbank are holders of our Preferred Units and may favor their interests in actions relating to such units, including causing us to make distributions on such units even if no distributions are made on the common units;

- Vitol and Charlesbank may compete with us, including with respect to future acquisition opportunities (either through Development Company or otherwise);

- Vitol and Charlesbank may favor their own interests in proposing the terms of any acquisitions we make directly from them or from Development Company, and such terms may not be as favorable as those we could receive from an unrelated third party;

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

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

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

- our General Partner 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 conflicts committee of our General Partner or 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.

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

Our partnership agreement contains provisions that reduce the fiduciary standards to which our General Partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

- permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its right to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights, the exercise of its limited call right, the exercise of its rights to transfer or vote the units it owns, the exercise of its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement;

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

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

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

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

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

Vitol and Charlesbank may compete with us, which could adversely affect our existing business and limit our ability to acquire additional assets or businesses.

Neither our partnership agreement nor any other agreement with Vitol or Charlesbank prohibits Vitol or Charlesbank from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Vitol or Charlesbank may acquire (either directly or through Development Company), 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. Vitol is a large, international organization and Charlesbank is a middle-market private equity investment firm. Each of Vitol and Charlesbank 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. As a result, competition from Vitol and Charlesbank 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 are determined by our General Partner, may be substantial and will reduce our cash available for distribution to our unitholders.

Pursuant to our partnership agreement, our General Partner and its affiliates, including Vitol and Charlesbank, are entitled to receive reimbursement for the payment of expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services may be substantial and reduce the amount of cash available for distribution to unitholders. 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 under our partnership agreement to reimburse or indemnify our General Partner. If we are unable or unwilling to reimburse or indemnify our General Partner, our General Partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Holders of our Preferred Units and common units have limited voting rights and are not entitled to elect our General Partner or its directors.

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

Control of our General Partner may be transferred to a third party without unitholder consent.

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

We may issue additional units without approval of our unitholders, which would dilute our unitholders' ownership interests.

Except in the case of (1) the issuance on or before June 30, 2015 of units senior to the common units or (2) the issuance of units that rank equal to or senior to the Preferred Units, our partnership agreement does not limit the number or price of additional limited partner interests that we may issue at any time without the approval of our unitholders. In addition, because we are a limited partnership, we will not be subject to the shareholder approval requirements relating to the issuance of securities (other than in connection with the establishment or material amendment of a stock option or purchase plan or the making or material amendment of any other equity compensation arrangement) contained in Nasdaq Marketplace Rule 5635. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

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

Our partnership agreement restricts the voting rights of unitholders, other than our General Partner and its affiliates, including Vitol and Charlesbank, owning 20% or more of any class of our partnership securities.

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

Even if holders of our Preferred Units or common units are dissatisfied, they cannot initially remove our General Partner without its consent.

Our unitholders will be unable initially to remove our General Partner without its consent because our General Partner and its affiliates own a sufficient number of units to be able to prevent its removal. The vote of the holders of at least 66 % of all outstanding units voting together as a single class is required to remove the General Partner. As of December 31, 2011, Vitol and Charlesbank collectively owned approximately 34.7% of our aggregate outstanding Preferred Units and common units.

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

As of March 9, 2012, the executive officers and directors of our General Partner beneficially own an aggregate of 173,809 common units and 39,064 Preferred Units and Vitol and Charlesbank collectively own 18,312,968 Preferred Units. The sale of these units in the public markets could have an adverse impact on the price of the units or on any trading market that may develop.

Our General Partner has a limited call right that may require our unitholders to sell their units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 80% of any class of units then outstanding, our General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of such class of units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Our unitholders also may incur a tax liability upon a sale of their units. As of December 31, 2011, Vitol and Charlesbank collectively owned 60.7% of our outstanding Preferred Units.

Units held by persons who are not Eligible Holders will be subject to the possibility of redemption.

Our General Partner has the right under our partnership agreement to institute procedures, by giving notice to each of our unitholders, that would require transferees of units and, upon the request of our General Partner, existing holders of our units to certify that they are Eligible Holders. The purpose of these certification procedures would be to enable us to establish a federal income tax expense as a component of the pipeline's cost of service for ratemaking purposes under current FERC policy applicable to entities that pass through their taxable income to their owners. Eligible Holders are individuals or entities subject to United States federal income taxation on the income generated by us or entities not subject to United States federal income taxation on the income generated by us, so long as all of the entity's owners are subject to such taxation. If these tax certification procedures are implemented, we will have the right to redeem the units held by persons who are not Eligible Holders at the lesser of the holder's purchase price and the then-current market price of the units. The redemption price would be paid in cash or by delivery of a promissory note, as determined by our General Partner.

Holders of our Preferred Units have a distribution preference and a liquidation preference, which may adversely impact the value of our common units.

The Preferred Units rank prior to our common units as to both distributions of available cash and distributions upon liquidation. Holders of our Preferred Units are entitled to quarterly distributions of 2.75% per unit per quarter (or 11.0% per unit on an annual basis). If we fail to pay in full any distribution on our Preferred Units, the amount of such unpaid distribution will accrue and accumulate from the last day of the quarter for which such distribution is due until paid in full. If we are liquidated, we may not have sufficient funds remaining after payment of amounts to our creditors and to holders of our Preferred Units to make any distribution to holders of our common units.

The conversion rate applicable to the Preferred Units will not be adjusted for all events that may be dilutive.

The number of our common units issuable upon conversion of the Preferred Units is subject to adjustment only for subdivisions, splits or certain combinations of our common units. The number of common units issuable upon conversion is not subject to adjustment for other events, such as employee option grants, offerings of our common units for cash or in connection with acquisitions or other transactions that may increase the number of outstanding common units and dilute the ownership of existing common unitholders. The terms of the Preferred Units do not restrict our ability to offer common units in the future or to engage in other transactions that could dilute our common units.

We have rights to require our preferred unitholders to convert their Preferred Units into common units, and we may exercise this mandatory conversion right at an undesirable time.

We have the right in certain circumstances, including if a certain number of Preferred Units are converted to common units or if certain distribution levels or trading price levels on the common units are reached, to force the conversion of all outstanding Preferred Units to common units. Vitol and Charlesbank, the owners of our General Partner, own enough Preferred Units such that if they converted all of them to common units, we could then force all remaining outstanding Preferred Units to convert to common units. As a result, our preferred unitholders may be required to convert their Preferred Units at an undesirable time and may not receive their expected return on investment.

Holders of the Preferred Units will not have rights to distributions as holders of common units until they acquire our common units.

Until our preferred unitholders acquire common units upon conversion of the Preferred Units, such preferred unitholders will have no rights with respect to distributions on our common units. Upon conversion, our preferred unitholders will be entitled to exercise the rights of a holder of our common units only as to matters for which the record date occurs after the date on which such Preferred Units were converted to our common units.

The Preferred Units are limited partner interests in our partnership and therefore are subordinate to any indebtedness.

The Preferred Units are limited partner interests in our partnership and do not constitute indebtedness. As such, the Preferred Units will rank junior to all indebtedness and other non-equity claims on our partnership with respect to assets available to satisfy claims on our partnership, including in a liquidation of our partnership.

Market interest rates may affect the value of our units.

One of the factors that will influence the price of our units will be the distribution yield on our units relative to market interest rates. An increase in market interest rates could cause the market price of the units to go down. The trading price of the units will also depend on many other factors, which may change from time to time, including:

- the market for similar securities;
- government action or regulation;
- general economic conditions or conditions in the financial markets; and
- our financial condition, performance and prospects.

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business.

Our unitholders could be liable for our obligations as if they were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- a unitholder's right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 and 17-804 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Unitholders

Our common unitholders have been and will be required to pay taxes on their share of our taxable income even if they have not or do not receive any cash distributions from us.

Because our unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash we distribute, our common unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, even if our common unitholders receive no cash distributions from us. In this regard, we did not pay a distribution to our common unitholders for the quarter ended June 30, 2008 through the quarter ended September 30, 2011. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on us being treated as a partnership for federal income tax purposes. If less than 90% of the gross income of a publicly traded partnership, such as us, for any taxable year is “qualifying income” from sources such as the transportation, marketing (other than to end users), or processing of crude oil, natural gas or products thereof, interest, dividends or similar sources, that partnership will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years. We have not requested and do not plan to request a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, then we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay additional state income tax at varying rates. Distributions would generally be taxed again to unitholders as corporate distributions and none of our income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of our units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay annually a Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas with respect to the prior year. Imposition of such a tax on us by Texas and, if applicable, by any other state will reduce the cash available for distribution to our unitholders.

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

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

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

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

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

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

If our unitholders sell their units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those units. Because distributions to a unitholder which exceed the total net taxable income allocated to the unitholder decrease the unitholder's tax basis in his or her units, any such prior excess distribution will, in effect, become taxable income to the unitholder if the common unit are sold by the unitholder at a price greater than their tax basis, even if the price the unitholder receives is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income to the selling unitholder due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, a unitholder who sells common units may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities, regulated investment companies and non-United States persons face unique tax issues from owning units that may result in adverse tax consequences to them.

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

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and/or amortization positions that may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from their sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

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

We will be considered to have terminated for federal income tax purposes if there are one or more transfers of interests in our partnership that together represent sales or exchanges of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met,

- multiple transfers of the same interest within a twelve month period will be counted only once; and
- if Vitol or Charlesbank sells or exchanges its interests in our General Partner, the interests held by our General Partner in us will be deemed to have been sold or exchanged.

While we would continue our existence as a Delaware limited partnership, our tax termination would, among other things, result in the closing of our taxable year for all unitholders which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief is not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A tax termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections, and if we were to fail to recognize and report on our tax return that a termination occurred, we could be subject to penalties. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the year in which the termination occurs notwithstanding two partnership tax years.

Our unitholders likely will be subject to state and local taxes and return filing or withholding requirements in states in which they do not live as a result of investing in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance, or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in certain of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in Texas, Oklahoma, Kansas, Colorado, New Mexico, Arkansas, California, Georgia, Idaho, Illinois, Indiana, Missouri, Michigan, Montana, Nebraska, Nevada, New Jersey, Ohio, Pennsylvania, Tennessee, Utah, Virginia and Washington. Most of these states currently impose income taxes on corporations, and many of these states impose income taxes on other entities and nonresident individuals. We may own property or conduct business in other states or foreign countries in the future. It is each unitholder's responsibility to file all federal, state and local tax returns. Under the tax laws of some states where we will conduct business, we may be required to withhold a percentage from amounts to be distributed to a unitholder who is not a resident of that state. For example, in the case of Oklahoma, we are required to either report detailed tax information about our non-Oklahoma resident unitholders with an income in Oklahoma in excess of $500 to the taxing authority, or withhold an amount equal to 5% of the portion of our distributions to unitholders which is deemed to be the Oklahoma share of our income. Our counsel has not rendered an opinion on the state and local tax consequences of an investment in our common units.

We have transferred certain assets located at certain of our asphalt facilities and which could generate non-qualifying income to a subsidiary taxed as a corporation. Such subsidiary is subject to entity level federal and state income taxes on its net taxable income and, if a material amount of entity-level taxes were incurred, then our cash available for distribution to our unitholders could be substantially reduced.

We have entered into storage contracts and leases with third party customers with respect to substantially all of our asphalt facilities. At the time of entering into such agreements, it was unclear under current tax law as to whether the rental income from the leases, and whether the fees attributable to certain of the processing services we provide under certain of the storage contracts, constitute "qualifying income." In the second quarter of 2009, we submitted a request for a ruling from the IRS that rental income from the leases constitutes "qualifying income." In October 2009, we received a favorable ruling from the IRS. As part of this ruling, however, we agreed to transfer, and have transferred, certain of our asphalt processing assets and related fee income, to a subsidiary taxed as a corporation. Such subsidiary is required to pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates. Distributions from such subsidiary will generally be taxed again to unitholders as corporate distributions and none of the income, gains, losses, deductions or credits of such subsidiary will flow through to our unitholders. If a material amount of entity-level taxes are incurred by such subsidiary, then our cash available for distribution to its unitholders could be substantially reduced.

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel has not rendered an opinion as to the validity of this method. Recently, the

U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our common unitholders.

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

Because a unitholder whose units are loaned to a "short seller" to effect a short sale of units may be considered as having disposed of the loaned units, such unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where units are loaned to a short seller to effect a short sale of units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Unitholders converting preferred units into common unit could under certain limited circumstances receive a gross income allocation that may materially increase the taxable income allocated to such unitholders.

Under our partnership agreement and in accordance with proposed Treasury Regulations, immediately after the conversion of a preferred unit, we will adjust the capital accounts of all of our partners to reflect any positive difference ("Unrealized Gain") or negative difference ("Unrealized Loss") between the fair market value and the carrying value of our assets at such time as if such Unrealized Gain or Unrealized Loss had been recognized on an actual sale of each such asset for an amount equal to its fair market value at the time of such conversion. Such Unrealized Gain or Unrealized Loss (or items thereof) will be allocated first to the converting preferred unitholder in respect of common units received upon the conversion until the capital account of each such common unit is equal to the per unit capital account for each existing common unit. This allocation of Unrealized Gain or Unrealized Loss will not be taxable to the converting preferred unitholder or to any other unitholders. If the Unrealized Gain or Unrealized Loss allocated as a result of the conversion of a preferred unit is not sufficient to cause the capital account of each common unit received upon such conversion to equal the per unit capital account for each existing common unit, then capital account balances will be reallocated among the unitholders as needed to produce this result. In the event that such a reallocation is needed, a converting preferred unitholder would be allocated taxable gross income in an amount equal to the amount of any such reallocation to it.

We may adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our General Partner and our common unitholders. The IRS may challenge this treatment, which could adversely affect the value of our outstanding units.

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

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

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is contained in "Item 1—Business."

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipelines were built was purchased in fee. Our crude oil terminals are on real property owned or leased by us.

Our asphalt assets are on real property owned or leased by us. Some of the real property leases that were transferred to us as part of the acquisition of our asphalt assets required the consent of the counterparty to such lease. In certain instances, we have not entered into new leases with a lessor although we continue to use such leases and make payments to the lessor and are in the process of negotiating new leases.

Other than as described above, we believe that we have satisfactory title to all of our assets. Although title to such properties is subject to encumbrances in certain cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens and minor easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or us, we believe that none of these burdens will materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings.

Concluded Matters

On May 3, 2011, we entered into a Stipulation of Settlement (the "Stipulation") to settle the consolidated securities class action litigation, In Re: SemGroup Energy Partners, L.P. Securities Litigation, Case No. 08-MD-1989-GKF-FHM (the "Class Action Litigation"), pending in the U.S. District Court for the Northern District of Oklahoma. As set forth more fully in the Stipulation, upon final approval by the court, among other things, the shareholder class received a total payment of approximately $28.0 million from the defendants. No parties admitted any wrongdoing as part of the settlement. On June 9, 2011, the Court entered an order preliminarily approving, subject to further consideration at a settlement hearing, the proposed settlement pursuant to the Stipulation involving, among other things, a dismissal of the Class Action Litigation with prejudice. The Court held a hearing on October 5, 2011 and granted final approval of the proposed settlement and issued a final judgment (the "Judgment") in accordance with the Stipulation. The Judgment became final on November 7, 2011.

On July 24, 2009, we filed suit against Navigators Insurance Company ("Navigators") and Darwin National Assurance Company ("Darwin") in Tulsa County district court. In that suit, we sought a declaratory judgment that Darwin and Navigators did not have the right to rescind binders issued to us for three excess insurance policies in their Directors and Officers insurance program for the period from July 18, 2008 to July 18, 2009. The suit also alleged that the attempted rescissions were in breach of contract and violated the duty of good faith and fair dealing, for which we sought recovery of damages and attorneys' fees. As part of the settlement of the Class Action Litigation described above, we entered in a Settlement Agreement and Release (the "Settlement Agreement") with Navigators and Darwin.

As described above, the Court held a hearing on October 5, 2011 and granted final approval of the proposed Class Action Litigation settlement and issued the final Judgment in accordance with the Stipulation signed in the Class Action Litigation. Pursuant to the Stipulation, the Judgment became final on November 7, 2011. Pursuant to the Settlement Agreement, we dismissed with prejudice the suit against Navigators and Darwin in the fourth quarter of 2011.

On July 21, 2008, we received a letter from the staff of the Securities and Exchange Commission (the “SEC”) giving notice that the SEC was conducting an inquiry relating to us and requesting, among other things, that we voluntarily preserve, retain and produce to the SEC certain documents and information relating primarily to our disclosures respecting SemCorp’s liquidity issues, which were the subject of our July 17, 2008 press release. On October 18, 2011, the SEC announced that it had reached a settlement with Thomas L. Kivisto, a former member of the Board, with respect to certain asserted claims against Mr. Kivisto. On November 28, 2011, the Partnership was notified by the Staff of the Fort Worth office of the SEC that the Staff has completed its investigation of the Partnership and does not intend to recommend any enforcement action by the SEC.

The Official Committee of Unsecured Creditors of SemCrude, L.P. (“Unsecured Creditors Committee”) filed an adversary proceeding in connection with SemCorp’s bankruptcy cases against Thomas L. Kivisto, Gregory C. Wallace, Kevin L. Foxx, Alex G. Stallings and Westback Purchasing Company, L.L.C. The Unsecured Creditors Committee asserted various claims against the defendants on behalf of SemCorp’s bankruptcy estate, including, among others, claims based upon theories of fraudulent transfer, breach of fiduciary duties, waste, breach of contract, and unjust enrichment. Messrs. Kivisto, Wallace, Cooper, Foxx and Stallings have reached an agreement with the Litigation Trust to settle the claims against them in the adversary proceedings described above. The settlement became final on October 26, 2011.

Pending Matters

On October 27, 2008, Keystone Gas Company (“Keystone”) filed suit against us in Oklahoma State District Court in Creek County alleging that it is the rightful owner of certain segments of our pipelines and related rights of way, located in Payne and Creek Counties, that we acquired from SemCorp in connection with our initial public offering in 2007. Keystone seeks to quiet title to the specified rights of way and pipelines and seeks damages up to the net profits derived from the disputed pipelines. There has been no determination of the extent of potential damages for our use of such pipelines. We have filed a counterclaim against Keystone alleging that it is wrongfully using a segment of a pipeline that is owned by us in Payne and Creek Counties. The parties are engaged in discovery. We intend to vigorously defend these claims. No trial date has been set by the court.

In March and April 2009, nine current or former executives of SemCorp and certain of its affiliates filed wage claims with the Oklahoma Department of Labor against our General Partner. Their claims arise from our General Partner’s Long-Term Incentive Plan, Employee Phantom Unit Agreement (“Phantom Unit Agreement”). Most claimants alleged that phantom units previously awarded to them vested upon the Change of Control that occurred in July 2008. One claimant alleged that his phantom units vested upon his termination. The claimants contended our General Partner’s failure to deliver certificates for the phantom units within 60 days after vesting caused them to be damaged, and they sought recovery of approximately $2.0 million in damages and penalties. On April 30, 2009, all of the wage claims were dismissed on jurisdictional grounds by the Department of Labor.

On July 8, 2009, the nine executives filed suit against our General Partner in Tulsa County district court claiming they are entitled to recover the value of phantom units purportedly due them under the Phantom Unit Agreement. The claimants assert claims against our General Partner for alleged failure to pay wages and breach of contract and seek to recover the alleged value of units in the total amount of approximately $1.3 million, plus additional damages and attorneys’ fees. We have distributed phantom units to certain of the claimants. On April 14, 2010, a Tulsa County district court judge ruled in favor of seven of the claimants, and awarded them approximately $1.0 million in damages. We have appealed this ruling. On October 22, 2010, our General Partner was ordered to pay $0.2 million in attorneys’ fees. We have also appealed this order.

Koch Industries, Inc. (together with its subsidiaries, “Koch”), a previous owner of our asphalt facility located in Northumberland, Pennsylvania, has alleged that we have a responsibility to assess the polychlorinated biphenyl (“PCB”) contamination at such facility although the contamination occurred prior to our becoming the owner of such facility. Koch claims that it was absolved of its responsibility to assess and clean up the site during SemCorp’s bankruptcy proceedings. We contend that Koch retained responsibility for such environmental issues and that SemCorp’s bankruptcy proceedings did not absolve Koch of these liabilities. On July 6, 2011, we filed an adversary complaint in connection with SemCorp’s bankruptcy cases against Koch seeking a declaration that SemCorp’s bankruptcy proceedings did not impact Koch’s responsibility to assess and clean the Northumberland site. A responsive pleading has been filed by Koch. We intend to vigorously defend against Koch’s allegation that we should be required to assess or clean up the PCB contamination.

On July 11, 2011, ExxonMobil filed suit against us in Harris County District Court, State of Texas, requesting damages in excess of $35,000 from us and other third party service providers in connection with the relocation of existing pipelines owned by ExxonMobil and us. We have filed our answer to the claims and asserted cross-claims against third party service providers including the subcontractors of ExxonMobil. ExxonMobil had previously sent a settlement demand seeking approximately $1.9 million in damages. We intend to vigorously defend these claims.

On February 6, 2012, we filed suit against SemCorp in Oklahoma County district court. SemCorp’s answer in the civil proceedings is due on March 26, 2012. In the suit, we are seeking a declaratory judgment that SemCorp immediately return approximately 140,000 barrels of crude oil linefill belonging to us, and we are seeking judgment in an amount in excess of $75,000 for actual damages, special damages, punitive damages, pre-judgment interest, reasonable attorney’s fees, and costs, and such other relief that the Court deems equitable and just.

We may become the subject of additional private or government actions regarding these matters in the future. Litigation may be time-consuming, expensive and disruptive to normal business operations, and the outcome of litigation is difficult to predict. The defense of these claims and lawsuits may result in the incurrence of significant legal expense. The litigation may also divert management’s attention from our operations which may cause our business to suffer. An unfavorable outcome in any of these matters may have an adverse effect on our business, financial condition, results of operations, cash flows, ability to make distributions to our unitholders, the trading price of our common units and ability to conduct our business. All or a portion of the defense costs and any amount we may be required to pay to satisfy a judgment or settlement of these claims may not be covered by insurance.

Item 4. Mine Safety Disclosures.

None.

PART II

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

Effective at the opening of business on February 20, 2009, trading in our common units was suspended on Nasdaq due to our failure to timely file our periodic reports with the SEC, and our common units were subsequently delisted from Nasdaq. Our common units were then traded on the Pink Sheets, which is an over-the-counter securities market, under the symbol BKEP.PK. On May 16, 2011, our common units were relisted and resumed trading on the Nasdaq Global Market exchange under the symbol "BKEP".

On March 9, 2012, there were 22,660,137 common units outstanding, held by approximately 17 unitholders of record of our common units. The actual number of unitholders is greater than the number of holders of record. We have also issued 30,159,958 Preferred Units, which began trading on the Nasdaq Global Market under the symbol "BKEPP" on November 14, 2011. 18,312,968 of the Preferred Units are held by Vitol and Charlesbank.

The following table shows the high and low sales prices per common unit, as reported by Nasdaq or the Pink Sheets, as applicable, as well as distributions declared by quarter for the periods indicated. The quotations from the Pink Sheets reflect inter-dealer prices, without retail mark-up, mark-down, or commission and may not necessarily represent actual transactions.

Common Units(1)	Low	High	Cash Distribution per Unit(2)	
2010:				
First Quarter	$ 7.50	$ 11.85	$ —	
Second Quarter	8.00	10.25	—	
Third Quarter	7.52	9.45	—	
Fourth Quarter	6.55	9.10	—	
2011:				
First Quarter	$ 7.25	$ 8.82	$ —	
Second Quarter	6.88	9.00	—	
Third Quarter	6.11	9.00	—	
Fourth Quarter	4.95	6.99	0.11	
Preferred Units(3)	**Low**	**High**	**Cash Distribution per Unit**	
2011:				
First Quarter	N/A	N/A	$ 0.24	(4)
Second Quarter	N/A	N/A	0.14	
Third Quarter	N/A	N/A	0.14	
Fourth Quarter	$ 7.33	$ 9.85	0.17	

(1) Our common units were traded on the Pink Sheets until May 16, 2011, when they were relisted on the NASDAQ Global Market.

(2) We did not make a distribution to our common unitholders or subordinated unitholders for the quarter ended June 30, 2008 through the quarter ended September 30, 2011 due, in part, to the events of default and covenants under our prior credit agreement and the uncertainty of our future cash flows.

(3) Our Preferred Units began trading on the Nasdaq on November 14, 2011.

(4) This amount includes $0.10 related to the portion of the quarter ending December 31, 2010 for which the Preferred Units were outstanding and $0.14 for the quarter ended March 31, 2011.

Distributions of Available Cash

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date.

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

- less the amount of cash reserves established by our General Partner to:

  - provide for the proper conduct of our business;

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

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

- plus all additional cash and cash equivalents on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within 12 months.

We had not made a distribution since May 15, 2008 due, in part, to the events of default and restrictive covenants under our prior credit agreement and the uncertainty of our future cash flows. As a result of the approval of the Partnership Agreement Amendment Proposal on September 14, 2011, all cumulative common unit arrearages were eliminated. Pursuant to our credit facility, we are permitted to make quarterly distributions of available cash to unitholders so long as: (i) no default or event of default exists under our credit agreement, (ii) we have, on a pro forma basis after giving effect to such distribution, at least $10.0 million of availability under the revolving loan facility, and (iii) our consolidated total leverage ratio, on a pro forma basis, would not be greater than (y) 4.25 to 1.00 for the fiscal quarter ended on December 31, 2011, or (z) 4.00 to 1.00 for any fiscal quarter ending on or after March 31, 2012. Our consolidated total leverage ratio (calculated in accordance with our credit agreement) as of December 31, 2011 was 3.19 to 1.00.

On January 24, 2012, the Board approved a distribution of $0.11 per common unit and $0.17 per Preferred Unit, or a total distribution of $7.6 million. The Partnership paid this distribution on February 14, 2012 to common and Preferred Unitholders of record as of February 3, 2012.

Distributions of Available Cash from Operating Surplus during the Eight Quarter Period

We will make distributions of available cash from operating surplus for any quarter during the eight quarter period ended June 30, 2013 (the “Eight Quarter Period”) in the following manner:

- first, 97.9% to the holders of the Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Preferred Unit an amount equal to the Series A Quarterly Distribution Amount (as defined below) for that quarter;

- second, 97.9% to the holders of the Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Preferred Unit an amount equal to any arrearages in the payment of the Series A Quarterly

Distribution Amount for any prior quarters; and

- thereafter, 97.9% to all unitholders holding common units, pro rata, and 2.1% to our General Partner.

Series A Quarterly Distribution Amount means (i) in the case of any quarter or partial quarter during the period ending on October 25, 2011, $0.138125 per unit and (ii) thereafter, $0.17875 per unit.

The preceding discussion is based on the assumptions that our General Partner maintains its 2.1% general partner interest and that we do not issue additional classes of equity securities.

Distributions of Available Cash from Operating Surplus after the Eight Quarter Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter after the Eight Quarter Period in the following manner:

- first, 97.9% to the holders of Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Series A Preferred Unit an amount equal to the Series A Quarterly Distribution Amount for that quarter;

- second, 97.9% to the holders of Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Series A Preferred Unit an amount equal to any arrearages in the payment of the Series A Quarterly Distribution Amount for any prior quarters;

- third, 97.9% to all common unitholders and Class B unitholders, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding common and Class B unit an amount equal to the minimum quarterly distribution of $0.11 per unit for that quarter; and

- thereafter, in the manner described in "—General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our General Partner maintains its 2.1% general partner interest and that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our General Partner will be entitled to an approximate 2.1% of all distributions that we make prior to our liquidation. Our General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its approximate 2.1% general partner interest if we issue additional units. Our General Partner's approximate 2.1% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future (other than the issuance of partnership securities issued in connection with a reset of the incentive distribution target levels relating to our General Partner's incentive distribution rights or the issuance of partnership securities upon conversion of outstanding partnership securities) and our General Partner does not contribute a proportionate amount of capital to us in order to maintain its then current general partner interest. Our General Partner will be entitled to make a capital contribution in order to maintain its then current general partner interest in the form of the contribution to us of common units based on the current market value of the contributed common units.

Incentive distribution rights represent the right to receive an increasing percentage (13%, 23% and 48%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our General Partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

The following discussion assumes that our General Partner maintains its approximate 2.1% general partner's interest and continues to own the incentive distribution rights.

If for any quarter after the Eight Quarter Period:

- we have distributed available cash from operating surplus to the holders of our Preferred Units in an amount equal to the Series A Quarterly Distribution Amount;

- we have distributed available cash from operating surplus to the holders of our Preferred Units in an amount necessary to eliminate any cumulative arrearages in the payment of the Series A Quarterly Distribution Amount; and

- we have distributed available cash from operating surplus to the common unitholders and Class B unitholders in an amount equal to the minimum quarterly distribution.

then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the unitholders and our General Partner in the following manner:

- first, 97.9% to all unitholders holding common units or Class B units, pro rata, and 2.1% to our General Partner, until each unitholder receives a total of $0.1265 per unit for that quarter (the "first target distribution");

- second, 97.9% to the holders of Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Series A Preferred Unit an amount equal to any arrearages in the payment of the Series A Quarterly Distribution Amount for any prior quarters;

- third, 74.9% to all unitholders holding common units or Class B units, pro rata, and 25.1% to our General Partner, until each unitholder receives a total of $0.1825 per unit for that quarter (the "third target distribution"); and

- thereafter, 49.9% to all unitholders holding common units or Class B units, pro rata, and 50.1% to our General Partner.

For equity compensation plan information, see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters—Securities Authorized for Issuance under Equity Compensation Plans."

Unregistered Sales of Securities

For information regarding recent sales of unregistered Preferred Units and Convertible Debentures in connection with our refinancing, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." In addition, in connection with the refinancing transaction, we issued 433,758 general partner units to our General Partner to maintain its general partner interest in us in exchange for aggregate consideration of $2,819,431 in an offering exempt from registration under Section 4(2) of the Securities Act.

In connection with issuance of certain vested awards under our General Partner's long-term incentive plan, we issued 3,272 general partner units to our General Partner to maintain its general partner interest in us in exchange for aggregate consideration of $25,540 in an offering exempt from registration under Section 4(2) of the Securities Act.

Pursuant to the Stipulation and Judgment, we issued and transferred 767,414 common units with a value equal to approximately $5.2 million to lead plaintiff's counsel in the Class Action Litigation on October 12, 2011. The transfer of the 767,414 common units was the final payment to the class required by the Stipulation and Judgment. Such common units were issued pursuant to the exemption from registration provided by Section 3(a)(10) of the Securities Act. For additional information regarding the settlement of the Class Action Litigation, see "Item 3. Legal Proceedings."

Item 6. Selected Financial Data.

The following table shows selected historical financial and operating data of our predecessor and historical financial and operating data of Blueknight Energy Partners, L.P. for the periods and as of the dates presented. The historical financial statements for periods prior to the contribution of the assets, liabilities and operations to us by SemCorp on July 20, 2007 reflect the assets, liabilities and operations of our predecessor, which were contributed to us on a carve out basis prior to the closing of our initial public offering. We refer to such assets, liabilities and operations as the Crude Oil Business. The Crude Oil Business had historically been a part of the integrated operations of SemCorp, and neither SemCorp nor our predecessor recorded revenue associated with the gathering, transportation, terminalling and storage services provided on an intercompany basis. SemCorp and our predecessor recognized only the costs associated with providing such services. Accordingly, revenues reflected in the historical financial statements of our predecessor represent services provided to third parties and do not include any revenues for services provided to SemCorp. In addition, our results of operations for the years ended December 31, 2010, 2009 and 2008 were affected by SemCorp's bankruptcy filings and related events, which resulted in decreased revenues and increased expenses.

Prior to SemCorp's bankruptcy filings and our subsequent settlement with SemCorp in such bankruptcy proceedings in April of 2009, we were party to various agreements with SemCorp and its subsidiaries. After the rejection of such agreements in SemCorp's bankruptcy proceedings, we experienced decreased volumes of crude oil that was terminalled, stored, transported and gathered as compared to our agreements with SemCorp. In addition, we have also experienced decreased revenues in our asphalt services business as compared to the revenues that we received under our terminalling agreement with SemCorp. In addition, we have experienced increased expenses since SemCorp's Bankruptcy Filings, including increased general and administrative expenses related to the costs of legal and financial advisors, increased interest expense related to certain events of default under and associated amendments of our prior credit facility and expenses incurred to refinance our prior credit facility. For these reasons and due to the other factors described in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation—Overview—Items Impacting the Comparability of Our Financial Results," our results of operations are not comparable to our predecessor's historical results and our historical results may not be indicative of our future results.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the historical financial statements and the accompanying notes thereto, including those included elsewhere in this annual report. The table should be read together with "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	2007	2008	2009	2010	2011
		(in thousands, except for per unit data)			
Statement of Operations Data:					
Service revenues:					
Third party revenue	$ 28,303	$ 48,295	$ 124,701	$ 129,083	$ 132,618
Related party revenue(2)	46,262	143,885	32,075	23,541	44,089
Total revenue	74,565	192,180	156,776	152,624	176,707
Expenses:					
Operating	67,182	104,078	96,125	97,655	114,843
General and administrative	13,595	43,085	28,137	20,454	17,311
Total expenses	80,777	147,163	124,262	118,109	132,154
Gain on settlement transaction	—	—	2,585	—	—
Loss contingency, net of expected insurance recovery	—	—	—	7,200	—
Operating income (loss)	(6,212)	45,017	35,099	27,315	44,553
Other (income) expense					
Interest expense(3)	6,560	26,951	51,399	48,638	32,898
Change in fair value of embedded derivative within convertible debt	—	—	—	6,650	(20,224)
Change in fair value of rights offering contingency	—	—	—	(4,384)	(1,883)
Income (loss) before income taxes	(12,772)	18,066	(16,300)	(23,589)	33,762
Provision for income taxes	141	291	205	207	287
Net income (loss)	$ (12,913)	$ 17,775	$ (16,505)	$ (23,796)	$ 33,475
Allocation of net income (loss) for purpose of calculating earnings per unit(1):					
General partners interest in net income (loss)	$ 240	$ 3,646	$ (326)	$ (470)	$ 912
Preferred partners interest in net income	$ —	$ —	$ —	$ —	$ 16,446
Accretion of discount on increasing rate preferred units	S —	$ —	$ —	$ —	$ 2,243
Beneficial conversion feature attributable to preferred units	$ —	$ —	$ —	$ 8,114	$ 43,259
Beneficial conversion feature attributable to repurchase of preferred units	$ —	$ —	$ —	$ —	$ (6,892)
Gain on extinguishment attributable to redemption of convertible debt, recorded as a capital transaction	$ —	$ —	$ —	$ —	$ (2,375)
Net Income (loss) available to limited partners	$ 12,965	$ 14,129	$ (16,179)	$ (31,440)	$ (20,118)
Basic and diluted net income (loss) per limited partner unit:					
Common units	$ 0.49	$ 0.45	$ (0.47)	$ (0.91)	$ (0.61)
Subordinated Units	$ 0.49	$ 0.45	$ (0.47)	$ (0.91)	$ (0.52)
Cash distributions per unit to limited partners:(4)					

Paid	$ 0.24	$ 0.74	$ —	$ —	$ —
Declared	$ 0.58	$ 0.40	$ —	$ —	$ 0.11
Cash distributions per unit to preferred partners:					
Paid	NA	NA	NA	$ —	$ 0.52
Declared	NA	NA	NA	$ 0.10	$ 0.58
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 102,239	$ 284,489	$ 274,492	$ 274,069	$ 266,355
Total assets	125,482	354,641	310,701	323,838	304,755
Long-term debt and capital lease obligations	91,959	449,221	419,000	244,329	220,781
Total division equity/partners' capital (deficit)	17,229	(126,643)	(142,179)	(37,743)	57,799

(1) Net income (loss) and net income (loss) per unit is presented for the period from July 20, 2007 through December 31, 2007.

(2) For the twelve months ended December 31, 2008, 2009, 2010, and 2011, we recognized revenues of $143.9 million, $26.5 million, $1.0 million, and $0.5 million, respectively, for services provided to SemCorp. Of these amounts, $143.9 million and $26.3 million are classified as related party revenues for the twelve months ended December 31, 2008 and 2009, respectively, while $0.2 million, $1.0 million, and $0.5 million are classified as third party revenue for the twelve months ended December 31, 2009, 2010 and 2011, respectively. Additionally, we provide services to Vitol. For the twelve months ended December 31, 2008, 2009, 2010, and 2011, we recognized revenues of $6.6 million, $9.4 million, $23.2 million, and $44.1 million, respectively, for services provided to Vitol. Of these amounts, $6.6 million and $8.4 million are classified as third party revenues for the twelve months ended December 31, 2008 and 2009, respectively. In the twelve months ended December 31, 2009, $1.0 million in revenue for services provided to Vitol subsequent to the Vitol Change of Control is classified as related party revenue. All revenue for services provided to Vitol for the twelve months ended December 31, 2010 and 2011 is classified as related party revenue.

(3) Interest expense before July 20, 2007 reflects interest on capital lease obligations and debt payable to SemCorp. Interest expense after July 20, 2007 and prior to October 25, 2010 includes interest expense incurred under our prior credit facility. Interest expense after October 25, 2010 includes interest expense under our credit facility, amortization of the convertible subordinated debenture discount, long-term payable to related party, and amortization of debt issuance costs.

(4) Cash distributions paid per unit to limited partners represent payments made per unit during the period stated. Cash distributions declared per unit to limited partners represent distributions declared per unit for the quarters within the period stated. Declared distributions were paid within 45 days following the close of each quarter.

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

Overview

We are a publicly traded master limited partnership with operations in twenty-three states. We provide integrated terminalling, storage, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and liquid asphalt cement. We manage our operations through four operating segments: (i) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services, and (iv) asphalt services.

Our History

We were formed as a Delaware limited partnership in 2007 to own, operate and develop a diversified portfolio of complementary midstream energy assets. A timeline of certain significant events since our formation is set forth below.

- July 23, 2007 - We completed our initial public offering and in connection therewith SemCorp contributed substantially all of its crude oil business to us.

- February 20, 2008 - We completed the acquisition of substantially all of our asphalt terminalling and storage assets from SemCorp and a public offering of additional common units in connection therewith.

- May 12, 2008 - We acquired the Eagle North Pipeline System from SemCorp.

- May 30, 2008 - We acquired an additional 2.0 million barrels of storage at Cushing, Oklahoma from SemCorp as well as a fee-based storage agreement with Vitol relating to such storage.

- July 17, 2008 - We issued a press release announcing that SemCorp was experiencing liquidity issues and was exploring various alternatives, including raising additional equity, debt capital or the filing of a voluntary petition for reorganization under Chapter 11 of the bankruptcy code to address these issues.

- July 18, 2008 - Manchester Securities Corp. and Alerian Finance Partners, LP exercised certain rights under a loan agreement with the owner of our General Partner and reconstituted the board of directors of our General Partner.

- July 22, 2008 - SemCorp filed voluntary petitions for reorganization under Chapter 11 of the bankruptcy code. We were not a party to SemCorp's bankruptcy filings.

- November 24, 2009 - Vitol completed the acquisition of our General Partner and reconstituted the Board and our General Partner's management team (the "Vitol Change of Control").

- December 1, 2009 - We changed our name to Blueknight Energy Partners, L.P.

- October 25, 2010 - We entered into a Global Transaction Agreement with Vitol and Charlesbank in connection with refinancing of our prior credit facility and issued preferred units to Vitol and Charlesbank in connection therewith. In addition, the Global Transaction Agreement provided that we would call a meeting of our unitholders and submit proposals relating to the reduction of the minimum quarterly distribution and targets related to the incentive distribution rights and the elimination of the cumulative common unit arrearage. Furthermore, Vitol and

Charlesbank entered into an agreement whereby Charlesbank would purchase 50% of the ownership interest in the entity that owns our General Partner and 50% of our outstanding subordinated units from Vitol.

- November 12, 2010 - Charlesbank acquired a 50% ownership interest in the entity that owns our General Partner and 50% of our outstanding subordinated units from Vitol (the “Charlesbank Change of Control”).

- May 12, 2011 - The Partnership, the General Partner, Vitol and Charlesbank entered into the First Amendment to Global Transaction Agreement to modify certain provisions relating to, among other things, the proposals to be submitted to our unitholders.

- September 14, 2011 - At a special meeting, our unitholders approved the proposals provided in the Global Transaction Agreement, including the reduction of the minimum quarterly distribution and targets related to the incentive distribution rights and the waiver the cumulative common unit arrearage. As a result, Vitol and Charlesbank transferred all of our outstanding subordinated units to us and we cancelled such subordinated units.

- October 3, 2011 - Pursuant to the Global Transaction Agreement, we commenced a rights offering. Pursuant to the terms of the rights offering, we distributed to our common unitholders of record as of the close of business on September 27, 2011, 0.5412 rights for each outstanding common unit, with each whole right entitling the holder to acquire, for a subscription price of $6.50, a newly issued Preferred Unit. The rights offering expired on October 31, 2011.

- November 1, 2011 - We announced the expiration of the rights offering. The rights offering was over-subscribed with total basic and over-subscription rights being exercised for over 20 million Preferred Units. Approximately 96% of basic subscription rights were exercised, leaving approximately 470,000 Preferred Units available to fulfill over-subscriptions. We issued a total of 11,846,990 Preferred Units to unitholders that exercised their rights, and we received proceeds of approximately $77 million from the rights offering. The net proceeds from the rights offering, after deducting expenses, were used to redeem Convertible Debentures in the aggregate principal amount of $50 million plus accrued interest thereon that we issued to Vitol and Charlesbank (the “Convertible Debentures”) and to repurchase an aggregate of 3,225,494 Preferred Units from Vitol and Charlesbank.

- November 14, 2011 - The Preferred Units began trading on the NASDAQ Global Market under the symbol “BKEPP.”

- January 10, 2012 - The Partnership announced the future resignation of the Chief Executive Officer of the Partnership’s general partner, Mr. James Dyer, who will remain as Chief Executive Officer until his successor is appointed. Mr. Dyer informed the Board on January 6, 2012 of his intended retirement. Mr. Dyer will continue to serve on the Board of Directors of the Partnership’s general partner.

- January 24, 2012 - The Partnership announced distributions for the quarter ended December 31, 2011 of $0.11 per common unit and $0.17 per preferred unit to its common and preferred unitholders of record as of the close of business on February 3, 2012. The distributions were paid on February 14, 2012.

Our Revenues

We have been pursuing opportunities to provide crude oil terminalling and storage services, crude oil pipeline services, crude oil trucking and producer field services and asphalt services to third parties. For the year ended December 31, 2011, we derived approximately 25% of our revenues from services we provided to Vitol, with the remainder of our services being provided to third parties.

We have successfully increased the utilization of our Mid-Continent pipeline system, and throughput during the second quarter of 2011 reached effective capacity on segments of the system. While we see opportunity to increase the utilization of our crude oil trucking and producer field services assets due to high demand for our services in the markets we currently serve, demand outpaces supply for qualified drivers in this industry and is delaying our realization of complete utilization of these assets. We are actively pursuing additional drivers, and we anticipate increased utilization of these assets in 2012. However, there can be no assurance that our efforts will be successful. Furthermore, effective August 1, 2011, we renegotiated the rates for the majority of our crude oil trucking services contracts, and have realized increased revenues in the third and fourth quarters of 2011 as a result.

We have long-term contracts in place for 43 of our 44 asphalt facilities. The majority of the leases and storage agreements related to these facilities have terms that expire at or near the end of 2016. We operate the asphalt facilities pursuant to the storage agreements while our contract counterparties operate the asphalt facilities that are subject to the lease agreements.

We are aggressively pursuing incremental volumes for our systems; however, these additional efforts may not be successful. If we are unable to generate sufficient third party revenues, we will continue to experience lower volumes in our system which could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our common units, our results of operations and ability to conduct our business.

Our Expenses

Our financial results as of December 31, 2011, reflect a $0.5 million allowance for doubtful accounts related to amounts due from third parties as of December 31, 2011. The allowance is related primarily to amounts due from third parties and was established as a result of certain third party customers netting amounts due them from SemCorp with amounts due to us. In connection with the Charlesbank Change of Control, we incurred professional fees of approximately $2.4 million related to the Global Transaction Agreement. In addition, due to the Charlesbank Change of Control, deferred payments under certain employment agreements with our employees were accelerated, resulting in the recognition of an additional $2.5 million of compensation expense for the twelve months ended December 31, 2010. Also, as a result of the Charlesbank Change of Control, all outstanding awards under the Long-Term Incentive Plan vested, resulting in an incremental $0.1 million in non-cash compensation expense for the twelve months ended December 31, 2010.

Our maintenance expenditures are increasing due both to a tank inspection program that we implemented in the first quarter of 2011 in response to new regulation of the asphalt industry and to previously deferred maintenance of our crude oil pipeline systems.

In 2009 and 2010, we experienced increased interest expenses and other costs due to the events of default that existed under our prior credit agreement and from entering into associated amendments to such prior credit agreement. In October of 2010, we entered into a new credit agreement and have experienced decreased interest expense in 2011 as a result. Furthermore, we recognized interest expense of $0.9 million and $4.3 million during the year ended December 31, 2010 and 2011, respectively, in relation to the Convertible Debentures that were redeemed on November 9, 2011.

Income Taxes

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which our subsidiary that is taxed as a corporation operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences and the net operating loss (“NOL”) carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. To the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provision in our consolidated statement of operations.

Under ASC 740, Accounting for Income Taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (a) the more positive evidence is necessary and (b) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion, or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years,
- whether the carry forward period is so brief that it would limit realization of tax benefits,
-

future revenue and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing service rates and cost structures, and

- our earnings history exclusive of the loss that gave rise to the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

Given that our subsidiary taxed as a corporation has no earnings history to consider in assessing the likelihood of realizing the benefits of our deferred tax assets and the fact that we anticipate this subsidiary will generate net operating losses for the foreseeable future, we have provided a full valuation allowance against our deferred tax asset as of December 31, 2011.

Our Assets and Services

Our network of assets provides our customers the flexibility to access multiple points for the receipt and delivery of crude oil and the terminalling, storage and processing of crude oil and asphalt cement. Our operations have minimal direct exposure to changes in crude oil and asphalt cement prices, but the volumes of crude oil and asphalt cement we gather, transport, terminal or store are indirectly affected by commodity prices. We generate revenues by charging a fee for services provided at each transportation stage as crude oil is shipped from its origin at the wellhead to destination points such as the Cushing Interchange, to refineries in Oklahoma, Kansas and Texas or to pipelines and by charging a fee for services provided for the terminalling and storage of crude oil and asphalt cement.

- Crude oil terminalling and storage assets and services. We provide crude oil terminalling and storage services at our terminalling and storage facilities located in Oklahoma and Texas. We currently own and operate an aggregate of approximately 7.8 million barrels of storage capacity. Of this storage capacity, approximately 6.6 million barrels are located at our terminal in Cushing, Oklahoma. Our Cushing terminal is strategically located within the Cushing Interchange, one of the largest crude oil marketing hubs in the United States and the designated point of delivery specified in all New York Mercantile Exchange, or NYMEX, crude oil futures contracts. Our terminals have a combined capacity to receive or deliver approximately 10.0 million barrels of crude oil per month. We also own approximately 10 acres of additional land within the Cushing Interchange where we can develop additional storage capacity.

- Crude oil pipeline assets and services. We own and operate three pipeline systems, the Mid-Continent system, the Longview system, and the Eagle North system, collectively consisting of approximately 1,289 miles of pipelines that gather crude oil for our customers and transport it to refiners, to common carrier pipelines for ultimate delivery to refiners or to terminalling and storage facilities owned by us and others. Our pipeline gathering and transportation system located in Oklahoma and the Texas Panhandle, which we refer to as the Mid-Continent system, has a combined length of approximately 820 miles. Our second pipeline gathering and transportation system located in East Texas, which we refer to as the Longview system, consists of approximately 330 miles of tariff-regulated crude oil gathering pipeline. Our third pipeline transportation system located in Oklahoma, which we refer to as the Eagle North Pipeline System, consists of approximately 139 miles of pipeline.

- Crude oil trucking and producer field services. In addition to our pipelines, we use our approximately 157 owned or leased tanker trucks to gather crude oil in Kansas, Oklahoma, Texas, New Mexico and Colorado for our customers at remote wellhead locations generally not connected to pipeline and gathering systems and transport the crude oil to aggregation points and storage facilities located along pipeline gathering and transportation systems. In connection with our gathering services, we also provide a number of producer field services, ranging from gathering condensates from natural gas producers to hauling production waste water to disposal wells.

- Asphalt Services. Our 44 asphalt cement terminals are located in 22 states and as such are well positioned to provide asphalt services in the market areas they serve throughout the continental United States. With our approximately 7.2 million barrels of total asphalt product and residual fuel oil storage capacity, we are able to provide our customers the ability to effectively manage their asphalt product storage and processing and marketing activities. We currently have storage contracts or leases with third party customers relating to 43 of our 44 asphalt facilities.

Factors That Will Significantly Affect Our Results

Commodity Prices. Although our current operations have minimal direct exposure to commodity prices, the volumes of crude oil and liquid asphalt cement we gather, transport, terminal or store are indirectly affected by commodity prices. Petroleum product prices may be contango (future prices higher than current prices) or backwardated (future prices lower than current prices) depending on market expectations for future supply and demand. Our terminalling and storage services benefit most from an increasing price environment, when a premium is placed on storage, and our gathering and transportation services benefit most from a declining price environment when a premium is placed on prompt delivery.

Volumes. Our results of operations are dependent upon the volumes of crude oil we gather, transport, terminal and store and asphalt we terminal, store and/or process. Our results of operations are impacted by our ability to utilize our pipeline and storage capacity to transport and store supplies of crude oil for our customers. An increase or decrease in the production of crude oil from the oil fields served by our pipelines or an increase or decrease in the demand for crude oil in the areas served by our pipelines and storage facilities will have a corresponding effect on the volumes we gather, transport, terminal and store. The production and demand for crude oil and liquid asphalt cement are driven by many factors, including the price for crude oil.

Acquisition Activities. We may pursue acquisition opportunities. These acquisition efforts may involve assets that, if acquired, would have a material effect on our financial condition, results of operations and cash flows. We can give no assurance that any such acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

Organic Expansion Activities. We may pursue opportunities to expand our existing asset base and consider constructing additional assets in strategic locations. The construction of additions or modifications to our existing assets, and the construction of new assets, involve numerous regulatory, environmental, political, legal and operational uncertainties beyond our control and may require the expenditure of significant amounts of capital.

Distributions to our Unitholders. We may make distributions to holders of our Preferred Units and common units as well as to our General Partner. To the extent that substantially all of our cash generated by our operations is used to make such distributions, we expect that we will rely upon external financing sources, including commercial bank borrowings and other debt and equity issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs.

Results of Operations

We manage our operations through four operating segments: (i) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services, and (iv) asphalt services.

The following table and discussion is a summary of our results of operating for each of the years ended December 31, 2009, 2010 and 2011:

	Year Ended December 31,		
	2009	2010	2011
		(in thousands)	
Service revenues:			
Crude oil terminalling and storage revenues:			
Third party	$ 39,662	$ 17,701	$ 11,067
Related party(1)	3,638	21,258	27,608
Total crude oil terminalling and storage revenues	43,300	38,959	38,675
Crude oil pipeline services revenues:			