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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2013

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: 000-50067

CROSSTEX ENERGY, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**16-1616605**
(State of organization)	(I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS DALLAS, TEXAS	**75201**
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code)
(214) 953-9500

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Exchange on which Registered
Common Units Representing Limited Partnership Interests	The NASDAQ Global Select Market

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: **None.**

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

Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether 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 for the past 90 days. Yes ☒ No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

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

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $1,263,121,436 on June 30, 2013, based on $20.32 per unit, the closing price of the Common Units as reported on The NASDAQ Global Select Market on such date.

At February 14, 2014, there were 91,534,187 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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CROSSTEX ENERGY, L.P.

PART I

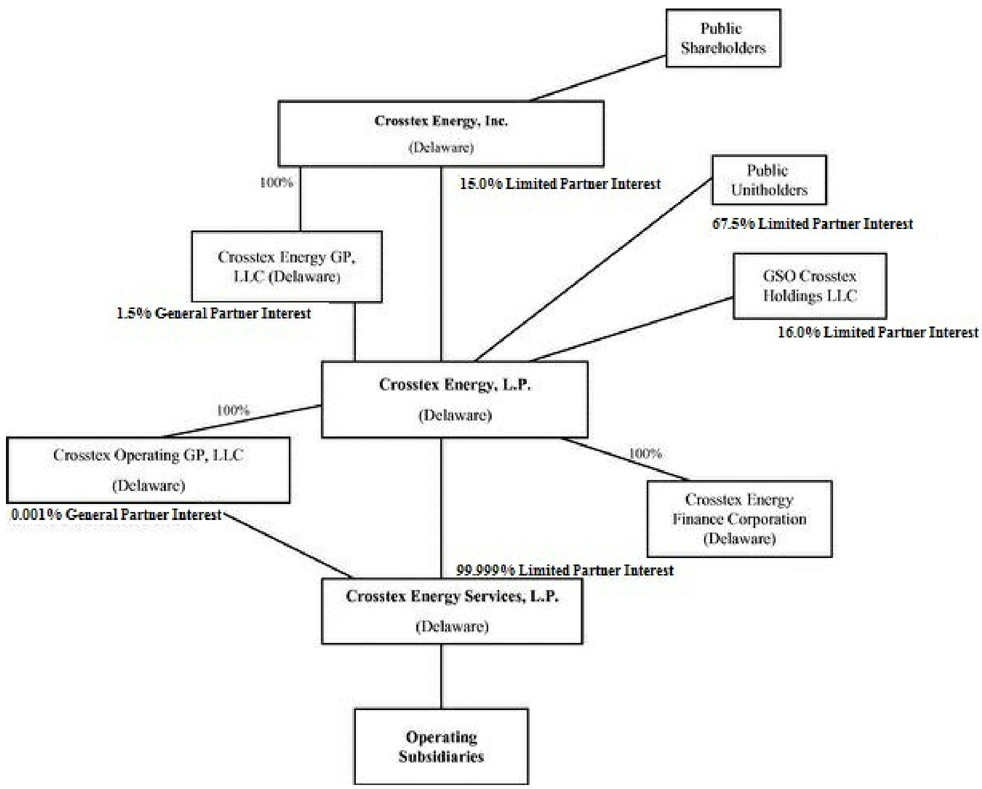
Item 1. ***Business***

General

Crosstex Energy, L.P. is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on The NASDAQ Global Select Market under the symbol "XTEX". Our business activities are conducted through our subsidiary, Crosstex Energy Services, L.P., a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership. Our executive offices are located at 2501 Cedar Springs, Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.crosstexenergy.com. We post the following filings in the "Investors" section of our website as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: our annual report on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our website are available free of charge. In this report, the terms "Partnership" and "Registrant," as well as the terms "our," "we," "us" and "its," are sometimes used as abbreviated references to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. together with its consolidated subsidiaries, including the Operating Partnership.

Crosstex Energy GP, LLC, a Delaware limited liability company, is our general partner. Crosstex Energy GP, LLC manages our operations and activities. Crosstex Energy GP, LLC is a wholly owned subsidiary of Crosstex Energy, Inc., or CEI. Crosstex Energy, Inc.'s shares are traded on The NASDAQ Global Select Market under the symbol "XTXI."

The following diagram depicts the organization and ownership of the Partnership as of December 31, 2013.



The following terms as defined generally are used in the energy industry and in this document:

/d = per day
Bbls = barrels
Bcf = billion cubic feet
Btu = British thermal units
CO_2= Carbon dioxide
Gal = gallon
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid and natural gas liquids

Capacity volumes for our facilities are measured based on physical volume and stated in cubic feet (Bcf, Mcf or MMcf). Throughput volumes are measured based on energy content and stated in British thermal units (Btu or MMBtu). A volume capacity of 100 MMcf generally correlates to volume capacity of 100,000 MMBtu. Fractionated volumes are measured based on physical volumes and stated in gallons (Gal). Crude oil, condensate and brine services volumes are measured based on physical volume and stated in barrels (Bbls).

Our Operations

We are a Delaware limited partnership formed on July12, 2002. We primarily focus on providing midstream energy services, including gathering, transmission processing, fractionation and marketing, to producers of natural gas, NGLs, crude oil and condensate. We also provide crude oil, condensate and brine services to producers. Our midstream energy asset network includes approximately 3,600 miles of pipelines, nine natural gas processing plants, four fractionators, 3.1 million barrels of NGL cavern storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. We manage and report our activities primarily according to geography. We have five reportable segments: (1) South Louisiana processing, crude and NGL, or PNGL, which includes our processing and NGL assets in south Louisiana; (2) Louisiana, or LIG, which includes our pipelines and processing plants located in Louisiana; (3) North Texas, or NTX, which includes our activities in the Barnett Shale and the Permian Basin; (4) Ohio River Valley, or ORV, which includes our activities in the Utica and Marcellus Shales; and (5) Corporate Segment, or Corporate, which includes our equity investment in Howard Energy Partners, or HEP, in the Eagle Ford Shale and our general partnership property and expenses. See Note 12 to the consolidated financial statements for financial information about these operating segments.

We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee arrangements. We provide a variety of crude oil and condensate services throughout the ORV which include crude oil and condensate gathering via pipelines, barges, rail and trucks and oilfield brine disposal. We also have crude oil and condensate terminal facilities in south Louisiana that provide access for crude oil and condensate producers to the premium markets in this area. Our gas gathering systems consist of networks of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. We also have NGL transmission lines that transport NGLs from east Texas and our south Louisiana processing plants to our fractionators in south Louisiana. Our crude oil and condensate gathering and transmission systems consist of trucking facilities, pipelines, rail and barges that, in exchange for a fee, transport oil from a producer site to an end user. Our processing plants remove NGLs and CO_2 from a natural gas stream and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

Our assets include the following:

- *North Texas Assets (including Permian Basin assets).* Our north Texas assets consist of gathering systems with total capacity of approximately 1.1 Bcf/d, processing facilities with a total processing capacity of approximately 315 MMcf/d and a transmission pipeline with a capacity of approximately 375 MMcf/d.
- *LIG System.* Our LIG system is one of the largest intrastate pipeline systems in Louisiana, consisting of approximately 2,000 miles of mainly transmission pipelines extending from the Haynesville Shale in north Louisiana to onshore production in south central and southeast Louisiana which have approximately 2.0 Bcf/d of

capacity. The LIG system also includes processing facilities with a total processing capacity of 335 MMcf/d and 10,800 Bbls/d of NGL fractionation capcity.

- *South Louisiana Processing and NGL Assets.* Our south Louisiana natural gas processing and liquid assets include approximately 1.4 Bcf/d of processing capacity, 83,000 Bbls/d of fractionation capacity, 3.1 million barrels of underground NGL storage, 570 miles of liquids transport lines and a crude oil terminal with a total capacity of 15,600 Bbls/d.
- *Ohio River Valley Assets.* Our Ohio River Valley assets include a 4,500-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot operation crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks. We have eight existing brine disposal wells with an injection capacity of approximately 10,000 Bbls/d. We currently hold one additional brine well permit in Ohio.

Our Business Strategy

Our business strategy consists of two overarching objectives, which are to maximize earnings and growth of our existing businesses and enhance the scale and diversification of our assets. As part of enhancing our scale and diversification, we have concentrated on expanding our NGL business, growing a crude oil and condensate business and developing our gas processing and transportation business in rich gas areas. We believe increasing our scale and diversification will strengthen us as a company because we believe it will lead to less reliance on any single geographic area, provide us with a better balance between business driven by crude oil and natural gas, offer us greater opportunities from a broader asset base and provide us with more sustainable fee-based cash flows.

Our strategies include the following:

- *Maximize earnings and growth of our existing businesses.* We intend to leverage our franchise position, infrastructure and customer relationships in our existing areas of operation by expanding our existing systems to meet new or increased demand for our gathering, transmission, processing and marketing services.
- *Enhance the scale and diversification of our assets.* We look to grow and diversify our business through acquiring and/or building assets in new areas that will serve as a platform for future growth with a focus on emerging shale plays and other areas with NGL, crude oil and condensate exposure.

Devon Energy Transaction

On October 21, 2013, the Partnership and the Operating Partnership entered into a Contribution Agreement (the “Contribution Agreement”) with Devon Energy Corporation (“Devon”) and certain of its wholly-owned subsidiaries pursuant to which two of Devon’s subsidiaries would contribute to the Operating Partnership 50% of the outstanding equity interests in EnLink Midstream Holdings, LP (formerly known as Devon Midstream Holdings, L.P.), a wholly-owned subsidiary of Devon referred to herein as “Midstream Holdings,” and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC (formerly known as Devon Midstream Holdings GP, L.L.C.), the general partner of Midstream Holdings (“Midstream Holdings GP” and, together with Midstream Holdings and their subsidiaries, the “Midstream Group Entities”) in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership (collectively, the “Contribution”) with a value of approximately $2.4 billion based on the volume weighted average closing prices of our common units for the 20 trading days prior to the announcement of the transaction. Upon completion of the Contribution, Devon and its affiliates will own approximately 53% of the limited partner interests in the Partnership, with approximately 39% of the outstanding limited partner interests held by the Partnership's public unitholders and approximately 7% of the outstanding limited partner interests (and the approximate 1% general partner interest) held indirectly by EnLink Midstream (as defined below).

The Midstream Group Entities own Devon’s midstream assets in the Barnett Shale in North Texas, the Cana and Arkoma Woodford Shales in Oklahoma and Devon’s interest in Gulf Coast Fractionators in Mont Belvieu, Texas. These assets consist of natural gas gathering and transportation systems, natural gas processing facilities and NGL fractionation facilities located in Texas and Oklahoma. Midstream Holdings' primary assets consist of three processing facilities with 1.3 Bcf/d of natural gas processing capacity, approximately 3,685 miles of pipelines with aggregate capacity of 2.9 Bcf/d and fractionation facilities with up to 160 MBbls/d of aggregate NGL fractionation capacity.

In connection with the Contribution Agreement, CEI entered into an Agreement and Plan of Merger (the “Merger Agreement”) with Devon and certain of its wholly-owned subsidiaries, EnLink Midstream, LLC (formerly known as New Public Rangers, L.L.C.), a holding company newly formed by Devon (“EnLink Midstream”), Rangers Merger Sub, Inc., a wholly-owned subsidiary of EnLink Midstream (“Rangers Merger Sub”), and Boomer Merger Sub, Inc., a wholly-owned subsidiary of EnLink Midstream

("Boomer Merger Sub"), pursuant to which Rangers Merger Sub will merge with and into CEI, and Boomer Merger Sub will merge with and into Acacia Natural Gas Corp I, Inc., a wholly-owned subsidiary of Devon ("New Acacia") (collectively, the "Mergers"), with CEI and New Acacia surviving as wholly-owned subsidiaries of EnLink Midstream. New Acacia owns the remaining 50% limited partner interest in Midstream Holdings. Devon will own the managing member of EnLink Midstream, and EnLink Midstream will indirectly own 100% of our general partner.

The closing of the Contribution is subject to the satisfaction of a number of conditions, including, but not limited to, the closing of the Mergers. The Merger is subject to customary closing conditions, including the approval of the proposal to adopt the merger agreement by the holders of at least 67% of the issued and outstanding shares of CEI's common stock entitled to vote as of the record date for the special meeting. The special meeting is scheduled to take place on March 7, 2014. The Contribution Agreement also contains customary termination provisions and will automatically terminate upon any termination of the Merger Agreement.

Recent Growth Developments

Cajun-Sibon Phases I and II. In Louisiana, we are transforming our business that historically has been focused on processing offshore natural gas to a business that is focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market historically has relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II will work to bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region.

We began this transformation by restarting our Eunice fractionator during 2011 at a rate of 15,000 Bbls/d of NGLs. We expanded the Eunice fractionator to a rate of 55,000 Bbls/d with Cajun-Sibon Phase I ("Phase I"). Phase I of our pipeline extension project was completed in November 2013 and connects Mont Belvieu supply lines in east Texas to Eunice, providing a direct link to our fractionators in south Louisiana markets. The Phase I Eunice fractionator expansion, which also was completed in early November 2013, has increased our interconnected fractionation capacity in Louisiana to approximately 97,000 Bbls/d of raw-make NGLs.

The Phase I expansion added 130-miles of 12-inch diameter pipeline to our existing 440-mile Cajun-Sibon NGL pipeline system, connecting Mont Belvieu to our Eunice fractionator. The pipeline currently has a capacity of 70,000 Bbls/d for raw make NGLs. The Phase I NGL pipeline extension originates from interconnects with major Mont Belvieu supply pipelines and provides connections for NGLs from the Permian Basin, Barnett Shale, Eagle Ford and other areas to our NGL fractionation facilities and key NGL markets in south Louisiana. Phase I is anchored by a five year ethane sales agreement with Williams Olefins, a subsidiary of the Williams Companies and a five year natural gasoline sales agreement with another company. We have entered into contracts of various lengths for all other purity products.

We have commenced construction of Cajun-Sibon Phase II which will further enhance our Louisiana NGL business with significant additions to the Cajun-Sibon Phase I infrastructure including further fractionation expansion. Phase II will include the addition of four pumping stations, totaling 13,400 horsepower, that will facilitate increasing NGL supply capacity from Phase I's 70,000 Bbls/d to 120,000 Bbls/d; the construction of a new 100,000 Bbls/d fractionator at the Plaquemine gas processing plant site; the conversion of our Riverside fractionator to a butane-and-heavier facility; and the construction of 57 miles of NGL pipeline that will originate at the Eunice fractionator and connect to the new Plaquemine fractionator, which will provide optionality to move purity products around the Louisiana-liquids market. We will also construct a 32-mile, 16-inch diameter extension of LIG's Bayou Jack lateral, which will provide gas services to customers in the Mississippi River corridor, replacing the conversion of supply lines that we currently use for liquid service. We expect Phase II will be in service during the second half of 2014.

Phase II is anchored by10-year sales agreements with Dow Hydrocarbons and Resources, or Dow, to deliver up to 40,000 Bbls/d of ethane and 25,000 Bbls/d of propane produced at our new Plaquemine fractionator into Dow's Louisiana pipeline system. We will also deliver 70,000 MMBtu/d of natural gas to Dow's Plaquemine facility.

We believe the Cajun-Sibon project not only represents a tremendous growth step by leveraging our Louisiana assets, but that it also creates a significant platform for continued growth of our NGL business. We believe this project, along with our existing assets, will provide a number of additional opportunities to grow this business, including expanding market optionality and connectivity, upgrading products, expanding rail imports, exporting NGLs and expanding fractionation and product storage capacity.

Bearkat Natural Gas Gathering and Processing System. In the fourth quarter of 2013, we commenced construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin. The initial construction included treating, processing and gas takeaway solutions for regional producers. The project, which will be fully owned by us, is supported by a 10-year, fee-based contract.

The new-build processing complex, called Bearkat, will be strategically located near our existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant will have an initial capacity of 60 MMcf/d, increasing the Partnership's total operated processing capacity in the Permian to approximately 115 MMcf/d. We will also construct a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan Counties. The entire project is scheduled to be completed in the second half of 2014.

Permian Pipeline Extension Project. In February 2014, the Partnership entered into an agreement to construct a new 35-mile, 12-inch diameter high-pressure pipeline that will provide critical gathering capacity for the aforementioned Bearkat natural gas processing complex. The pipeline will have a capacity of approximately 100 MMcf/d and will provide gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. Right-of-way acquisition is underway and the pipeline is expected to be operational in the second half of 2014.

Riverside Crude Facility Expansion. In June 2013, we completed the Phase II expansion of our Riverside facility located on the Mississippi River in southern Louisiana. The Riverside facility's capacity to transload crude oil and condensate from railcars to our barge facility increased to approximately 15,000 Bbls/d of crude oil and condensate. Phase II additions to the Riverside facility include a 100,000 barrel above-ground crude oil and condensate storage tank, a rail spur with a 26-spot crude railcar unloading rack and a crude oil and condensate offloading facility with pumps and metering as well as a truck unloading bay. As part of the Phase II expansion, the Riverside facility was modified so that sour crude can be unloaded in addition to sweet crude.

Our Assets

North Texas Assets (including Permian Basin assets). Our gathering systems in north Texas, or NTG, consist of approximately 715 miles of gathering lines that had an average throughput of approximately 700,000 MMBtu/d for the year ended December 31, 2013. Our processing facilities in north Texas include three gas processing plants with total processing throughput that averaged 382,000 MMBtu/d for the year ended December 31, 2013. Our transmission asset, referred to as the North Texas Pipeline, or NTPL, is a 140-mile pipeline from an area near Fort Worth, Texas to a point near Paris, Texas and related facilities. The NTPL connects production from the Barnett Shale to markets in north Texas accessed by the Natural Gas Pipeline Company of America, LLC, Kinder Morgan, Inc., Houston Pipeline Company, L.P., Atmos Energy Corporation and Gulf Crossing Pipeline Company, LLC. For the year ended December 31, 2013, the average throughput on the NTPL was approximately 342,000 MMBtu/d.

Our north Texas segment also includes our Deadwood natural gas processing plant and our Mesquite Terminal and fractionator that comprise our Permian Basin assets. We have a 50% undivided working interest in the Deadwood processing facility which is located in Glasscock County, Texas. The Deadwood plant is supported by acreage dedication from a major producer in the Permian Basin. The Deadwood processing facility has a total capacity of 58 MMcf/d and total processing throughput that averaged 66,000 MMBtu/d for the year ended December 31, 2013. The Mesquite Terminal is located in Midland County and serves as a terminal for third party raw-make NGLs. We are also transloading crude oil at this facility.

LIG Assets. The LIG gathering and transmission pipeline system is comprised of a north and south system and had an average throughput of approximately 473,000 MMbtu/d for the year ended December 31, 2013. The southern part of our LIG system has a capacity in excess of 1.5 Bcf/d and approximately 1,125 miles of pipeline. The south system also includes two operating, on-system processing plants, our Plaquemine and Gibson plants, with an average throughput of 255,000 MMBtu/d for the year ended December 31, 2013. The Plaquemine plant also has a fractionation capacity of 10,800 Bbls/d of raw-make NGL products, and total volume for fractionated liquids at Plaquemine averaged approximately 4,800 Bbls/d for the year ended December 31, 2013. The south system has access to both rich and lean gas supplies from onshore production in south central and southeast Louisiana. LIG has a variety of transportation and industrial sales customers in the south, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans.

Our LIG system in the north, comprised of approximately 800 miles of pipeline, serves the natural gas fields south of Shreveport, Louisiana and extends into the Haynesville Shale gas play in north Louisiana. The north Louisiana system has a capacity of 465 MMcf/d and interconnects with interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission, Trunkline Gas and Tennessee Gas Pipeline. We have a substantial number of firm transportation agreements on the north system with weighted average lives of approximately 4.3 years. Our north Louisiana system is connected to our south Louisiana system and has the capacity to move approximately 145 MMcf/d of gas to our markets in the south.

In August 2012, a slurry-filled sinkhole developed in Assumption Parish near Bayou Corne, Louisiana and in the vicinity of certain of our pipelines and our underground storage reservoir located in Napoleonville, Louisiana. The cause of the slurry is currently under investigation by Louisiana state and local officials. Consequently, we took a section of our 36-inch-diameter natural gas pipeline located near the sinkhole out of service. Service to certain markets, primarily in the Mississippi River area, has been curtailed or interrupted, and we have worked with our customers to secure alternative natural gas supplies so that disruptions are minimized. We are currently in the initial phase of constructing the replacement pipeline in our rerouted location and anticipate the re-route to be completed during the first half of 2014. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Changes in Operations During 2013 and 2012" for further information about this matter.

PNGL Assets. Our south Louisiana natural gas processing and liquids assets include processing and fractionation capabilities, underground storage and approximately 570 miles of liquids transport lines. Total processing throughput averaged 399,000 MMBtu/d and fractionated barrels averaged 27,300 Bbls/d for the year ended December 31, 2013.

- *NGL Assets.* Our NGL assets include our Eunice fractionation facility, our Riverside fractionation plant, our Cajun-Sibon pipeline system and our Napoleonville storage facility.
    - *Eunice Fractionation Facility.* The Eunice fractionation facility is located in south central Louisiana and was restarted in 2011 to take advantage of the activity around liquids rich shale-plays, including the Eagle Ford, Permian, Granite Wash, Marcellus and Utica plays. The Eunice fractionation facility has a capacity of 55,000 Bbls/d of liquid products, including ethane, propane, iso-butane, normal butane and natural gasoline, and is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility. The plant fractionated 5,100 Bbls/d of liquids during 2013. Our Plaquemine facility is connected to the PNGL system, which gives us operational flexibility, increased fractionation capacity and the ability to capture new NGL-related business. See "Recent Growth Developments" for a discussion of the Eunice expansion in conjunction with the Cajun-Sibon project.
    - *Riverside Fractionation Plant.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of approximately 28,000 Bbls/d of liquids delivered by the Cajun-Sibon pipeline system from the Eunice, Pelican and Blue Water processing plants or by truck and rail. The Riverside facility has above-ground storage capacity of approximately 233,000 Bbls. The loading/unloading facility has the capacity to transload 15,000 Bbls/d of crude oil and condensate from rail cars to barges. Total volumes for fractionated liquids at Riverside averaged 22,200 Bbls/d for the year ended December 31, 2013. See "Recent Growth Developments" for discussion of the expansion at Riverside in conjunction with the Cajun-Sibon project.
    - *Cajun-Sibon Pipeline System.* Currently, the Cajun-Sibon pipeline system consists of approximately 570 miles of raw make NGL pipelines ranging in size from 4" to 12" with a current system capacity of approximately 70,000 Bbls/d. The pipelines transport unfractionated NGLs, referred to as raw make, from areas such as the Liberty, Texas interconnects near Mont Belvieu and from our Eunice and Pelican processing plants in south Louisiana to either the Riverside or Eunice fractionators or to third party fractionators when necessary. See "Recent Growth Developments" for information regarding the expansion of this pipeline system.
    - *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of 3.1 million barrels of underground storage comprised of two existing caverns. The caverns are currently operated in propane and butane service, and space is leased to customers for a fee.
- *Processing Assets.* Our processing assets include our Pelican processing plant, our Eunice processing plant and our Blue Water gas processing plant.
    - *Pelican Processing Plant.* The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. For the year ended December 31, 2013, the plant processed approximately 334,000 MMBtu/d. The Pelican plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline. This plant has an interconnection with the LIG pipeline so we can process natural gas from the LIG system at our Pelican plant when markets are favorable.
    - *Eunice Processing Plant.* The Eunice processing plant is located in south central Louisiana, has a capacity of 475 MMcf/d and processed approximately 31,000 MMBtu/d for the year ended December 31, 2013. The plant is connected to onshore gas supply as well as continental shelf and deepwater gas production and has downstream connections to the ANR Pipeline, Florida Gas Transmission and Texas Gas Transmission. In August 2013, we shut down the Eunice processing plant

due to adverse economics driven by low NGL prices and low processing volumes, which we do not see improving in the near future based on forecasted price curves.

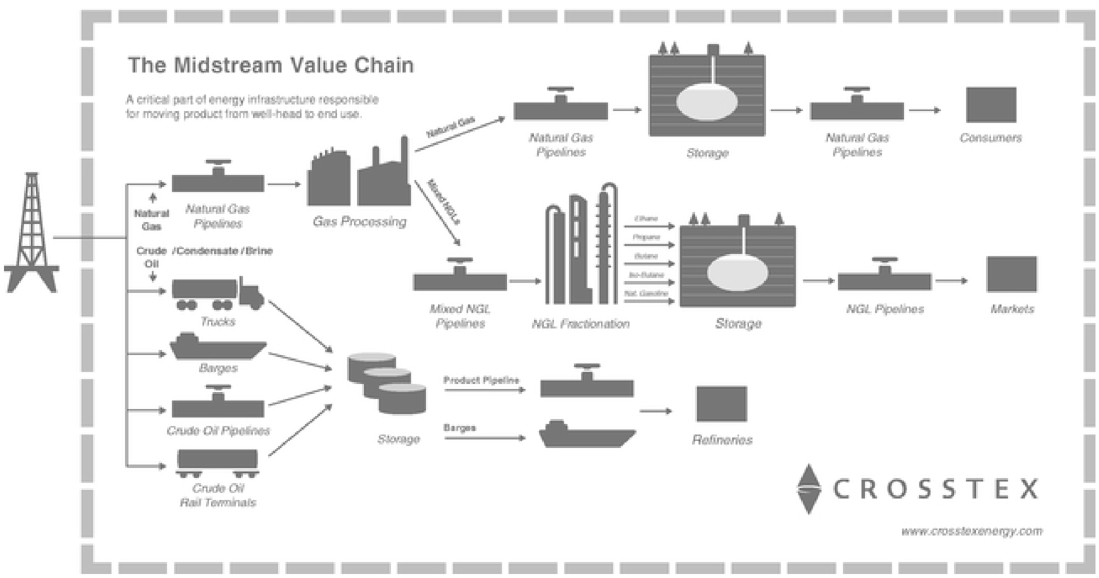
- *Blue Water Gas Processing Plant.* We own a 64.29% interest in the Blue Water gas processing plant and operate the plant. The Blue Water plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. The plant has a net capacity to our interest of approximately 300 MMcf/d. The plant is not expected to operate in the future unless fractionation spreads are favorable and volumes are sufficient to run the plant.

Ohio River Valley Assets. Our Ohio River Valley assets include a 4,500-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks with a current capacity of 25,000 Bbls/d. Total crude oil and condensate handled averaged approximately 11,000 Bbls/d for the year ended December 31, 2013. We have eight existing brine disposal wells with an injection capacity of approximately 10,000 Bbls/d and an average disposal rate of 7,000 Bbls/d for the year ended December 31, 2013. We currently hold one additional well permit in Ohio.

Investment in Limited Liability Company. In 2011 and 2012, we made capital contributions totaling $87.3 million to HEP in exchange for an individual ownership interest in HEP. HEP owns midstream assets and provides midstream and construction services to Eagle Ford Shale producers and is continuing to expand its midstream assets in the area. As of December 31, 2013, we owned a 30.6% interest in HEP and accounted for this investment under the equity method of accounting. In December 2013, Alinda Capital Partners acquired a 59 percent capital interest in HEP from Quanta Capital Solutions and GE Energy Financial Services. We contributed an additional $30.6 million to HEP during the year ended December 31, 2013 to fund our 30.6% share of HEP's expansion costs. We also received cash distributions totaling$17.5 million from HEP during the year ended December 31, 2013. Our investment in HEP is included in our Corporate segment.

Industry Overview

The following diagram illustrates the gathering, processing, fractionation and transmission process.



The midstream industry is the link between the exploration and production of natural gas, crude oil and condensate and the delivery of its components to end-user markets. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas, crude oil and condensate producing wells.

Natural gas gathering. The natural gas gathering process follows the drilling of wells into gas-bearing rock formations. After a well has been completed, it is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression and treating systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Compression. Gathering systems are operated at pressures that will maximize the total natural gas throughput from all connected wells. Because wells produce gas at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against the higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver gas into a higher-pressure downstream pipeline. The remaining natural gas in the ground will not be produced if field compression is not installed because the gas will be unable to overcome the higher gathering system pressure. In contrast, a declining well can continue delivering natural gas if the field compression is installed.

Natural gas processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of heavier NGLs and contaminants, such as water and CO_2, sulfur compounds, nitrogen or helium. Natural gas produced by a well may not be suitable for long-haul pipeline transportation or commercial use and may need to be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems mostly consists of methane and ethane, and moisture and other contaminants have been removed so there are negligible amounts of them in the gas stream. Natural gas is processed to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas and to separate those hydrocarbon liquids from the gas that have higher value as NGLs. The removal and separation of individual hydrocarbons through processing is possible due to differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream and the removal of contaminants.

NGL fractionation. NGLs are separated into individual, more valuable components during the fractionation process. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane, natural gasoline and stabilized crude oil and condensate. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used as a petrochemical feedstock in the production of ethylene and propylene and as a heating fuel, an engine fuel and industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butylene (a key ingredient in synthetic rubber), as a blend stock for motor gasoline and to derive isobutene through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.

Natural gas transmission. Natural gas transmission pipelines receive natural gas from mainline transmission pipelines, processing plants and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

Crude oil and condensate transmission. Crude oil and condensate are transported by pipelines, barges, rail cars and tank trucks. The method of transportation used depends on, among other things, the resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of product being transported.

Brine gathering and disposal services. Typically, shale wells produce significant amounts of water that, in most cases, require disposal. Produced water and frac-flowback is hauled via truck transport or is pumped through pipelines from its origin at the oilfield tank battery or drilling pad to the disposal location. Once the water reaches the delivery disposal location, water is processed and filtered to remove impurities and injection wells place fluids underground for storage and disposal.

Crude oil and condensate terminals. Crude oil and condensate rail terminals are an integral part of ensuring the movement of new crude oil and condensate production from the developing shale plays in the United States and Canada. In general, the crude oil and condensate rail loading terminals are used to load rail cars and transport the commodity out of developing basins into market rich areas of the country where crude oil and condensate rail unloading terminals are used to unload rail cars and store crude oil and condensate volumes for third parties until the crude oil and condensate is redelivered to premium markets via pipelines, trucks or rail to delivery points.

Balancing Supply and Demand

When we purchase natural gas, crude oil and condensate, we establish a margin normally by selling it for physical delivery to third-party users. We can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the New York Mercantile Exchange (the "NYMEX") related to our natural gas purchases. Through these transactions, we seek to maintain a position that is balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

Competition

The business of providing gathering, transmission, processing and marketing services for natural gas, NGLs, crude oil and condensate is highly competitive. We face strong competition in obtaining natural gas, NGLs, crude oil and condensate supplies and in the marketing and transportation of natural gas, NGLs, crude oil and condensate. Our competitors include major integrated and independent exploration and production crude oil and condensate companies, natural gas producers, interstate and intrastate pipelines, other natural gas and crude oil and condensate gatherers and natural gas processors. Competition for natural gas and crude oil supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. Many of our competitors offer more services or have greater financial resources and access to larger natural gas, NGLs, crude oil and condensate supplies than we do. Our competition varies in different geographic areas.

In marketing natural gas and NGLs, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil and gas companies, and local and national natural gas producers, gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly and through affiliates in marketing activities that compete with our marketing operations.

We face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition increases the cost to acquire existing facilities or businesses and results in fewer commitments and lower returns for new pipelines or other development projects. Many of our competitors have greater financial resources or lower cost of capital or are willing to accept lower returns or greater risks. Our competition differs by region and by the nature of the business or the project involved.

Natural Gas, NGL, Crude Oil and Condensate Supply

Our gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which we believe have ample natural gas and NGLs supplies in excess of the volumes required for the operation of these systems. Our Ohio River Valley pipeline, terminals, trucks and storage facilities are strategically located in oil and condensate producing regions. We evaluate well and reservoir data that is either publicly available or furnished by producers or other service providers in connection with the construction and acquisition of our gathering systems and assets to determine the availability of natural gas, NGL, crude oil and condensate supply for our systems and assets and/or obtain a minimum volume commitment from the producer that results in a rate of return on investment. We do not routinely obtain independent evaluations of reserves dedicated to our systems and assets due to the cost and relatively limited benefit of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems and assets or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

We are diligent in attempting to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of oil, gas and other products exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to our overall profitability.

During the year ended December 31, 2013, we had only one customer, Dow, which represented greater than 10.0% of our revenue. While this customer represented 12.6% of consolidated revenues, the loss of this customer would not have a material impact on our results of operations because the gross operating margins received from transactions with this customer are not material to our total gross operating margin, and we believe the sales to this customer could be replaced with other buyers at comparable sales prices.

Regulation

Interstate Natural Gas Pipelines Regulation. We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or FERC, does not directly regulate our natural gas operations under the National Gas Act, or NGA. However, FERC's regulation of interstate natural gas pipelines influences certain aspects of our business and the market for our products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;

- the acquisition and disposition of facilities;
- maximum rates payable for certain services; and
- the initiation and discontinuation of services.

While we do not own any interstate natural gas pipelines, we do transport gas in interstate commerce. The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. The maximum rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate," as defined in the NGPA. The rates are generally subject to review every three years by FERC or by an appropriate state agency. The inability to obtain approval of rates at acceptable levels could result in refund obligations, the inability to achieve adequate returns on investments in new facilities and the deterrence of future investment or growth of the regulated facilities.

Liquids Pipelines Regulation. We own liquids transportation, storage and other assets in the Ohio River Valley, including certain assets providing common carrier interstate service subject to regulation by FERC under the Interstate Commerce Act, or ICA, the Energy Policy Act of 1992 and related rules and orders. Our Cajun-Sibon NGL pipeline became subject to FERC regulation as a result of our Phase I expansion, which went into operation in November 2013. The expansion is subject to regulation by FERC as a common carrier under the ICA, the Energy Policy Act of 1992 and related rules and orders.

FERC regulation requires that interstate liquids pipeline rates and terms and conditions of service, including rates for transportation of crude oil and NGLs, be filed with FERC and that these rates and terms and conditions of service be "just and reasonable" and not unduly discriminatory or unduly preferential.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC's regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-services approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. 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. Under certain circumstances, FERC could limit our ability to set rates based on our costs or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change our terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As we acquire, construct and operate new liquids assets and expand our liquids transportation business segment, the classification and regulation of our liquids transportation services are subject to ongoing assessment and change based on the services we provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC.

Intrastate Natural Gas Pipeline Regulation. Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

Intrastate NGL Pipeline Regulation. Intrastate NGL and other petroleum pipelines are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

We are subject to some state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply.

Sales of Natural Gas and NGLs. The price at which we sell natural gas and NGLs currently are not subject to federal regulation and, for the most part, are not subject to state regulation. Our natural gas and NGL sales are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas and NGL industries, most notably interstate natural gas transmission companies and NGL pipeline companies that remain subject to FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes on our natural gas and NGL marketing operations, but we do not believe that we will be affected by any such FERC action in a manner that is materially different from the natural gas and NGL marketers with whom we compete.

Environmental Matters

General. Our operations involve processing and pipeline services for delivery of hydrocarbons (natural gas, NGLs, petroleum and fractionates) from point-of-origin at oil and gas wellheads operated by our suppliers to our end-use market customers. Our facilities include natural gas processing and fractionation plants, brine disposal wells, pipelines and associated facilities, fractionation and storage units for NGLs, and transportation and delivery of petroleum. As with all companies in our industrial sector, our operations are subject to stringent and complex federal, state and local laws and regulations relating to release of hazardous substances or solid wastes into the environment or otherwise relating to protection of the environment. Compliance with existing and anticipated environmental laws and regulations increases our overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines, and other facilities, as well as capital cost items necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon changes in laws or regulations and upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures, and obtaining required governmental approvals, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in less common circumstances, issuance of temporary or permanent injunctions or construction or operation bans or delays.

The continuing trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with possible future operations, and we cannot assure you that we will not incur significant costs and liabilities, including those relating to claims for damage to property and persons as a result of any such upsets, releases or spills. In the event of future increases in environmental costs, we may be unable to pass on those cost increases to our customers. A discharge of hazardous substances or solid wastes into the environment could, to the extent losses related to the event are not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and to pay fines or penalties that may be assessed and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to natural resources or property. We will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly to comply with changing environmental laws and regulations and to minimize costs with respect to more stringent future laws and regulations or more rigorous enforcement of existing laws and regulations.

Hazardous Substances and Waste. Environmental laws and regulations that relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water and/or include measures to prevent and control pollution may pose the highest potential cost to our industry sector. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous wastes and may require investigatory and corrective actions at facilities where such waste may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, also known as the federal "Superfund" law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of "hazardous substance" into the environment. Potentially liable persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the Environmental Protection Agency (EPA) and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the potentially responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment. Although petroleum, natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of ordinary operations, we may generate wastes that may fall within the definition of a "hazardous substance." In addition, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, we may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such wastes have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state law.

We also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and/or comparable state statutes. From time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. Moreover, it is possible that some wastes generated by us that are currently considered nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Changes in applicable laws or regulations may result in an increase in our capital expenditures or plant operating expenses or otherwise impose limits or restrictions on our production and operations.

We currently own or lease, have in the past owned or leased, and in the future may own or lease, properties that have been used over the years for brine disposal operations, crude and condensate transportation, natural gas gathering, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes may have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whose operations and hydrocarbon and waste management practices we had no control. These properties and wastes disposed thereon may be subject to the Safe Drinking Water Act, CERCLA, RCRA and analogous state laws. Under these laws, we could be required, alone or in participation with others, to remove or remediate previously disposed wastes or property contamination, if present, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. Our current and future operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and impose various controls together with monitoring and reporting requirements. Pursuant to these laws and regulations, we may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission-related issues. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition or operating results, and the requirements are not expected to be more burdensome to us than to any similarly situated company.

On April 17, 2012, the EPA approved final rules under the Clean Air Act that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules became effective on October 15, 2012. For new or reworked hydraulically-fractured gas wells, the rules require the control of emissions through flaring or reduced emission (or "green") completions until 2015, when the rules require the use of green completions by all such wells except wildcat (exploratory) and delineation gas wells and low reservoir pressure non-wildcat and non-delineation gas wells. The rules also establish specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2012, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2013. In addition, the rules revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines, effective October 15, 2012. These rules may therefore require a number of modifications to our and our suppliers' and customers' operations, including the installation of new equipment to control emissions.

In October 2012, several challenges to the EPA's April 17, 2012 rules were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. The case remains in abeyance. EPA issued a final rule revising certain aspects of the rules on August 5, 2013 and has indicated that it may reconsider other aspects of the rules. Depending on the outcome of such proceedings, the rules may be further modified or rescinded or the EPA may issue new rules. The costs of compliance with any modified or newly issued rules cannot be predicted. Additionally, on December 11, 2012, seven states submitted a notice of intent to sue the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from the oil and gas sector are appropriate, which was not addressed in the EPA rule that became effective on October 15, 2012. The notice of intent also requested that the EPA issue emission guidelines for the control of methane emissions from existing oil and gas sources. Depending on whether such rules are promulgated and the applicability and restrictions in any promulgated rule, compliance with such rules could result in additional costs, including increased capital expenditures and operating costs for us and for other companies in our industry. While we are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for us. Compliance with such rules, as well as any new state rules, may also make it more difficult for our suppliers and customers to operate, thereby reducing the volume of natural gas transported through our pipelines, which may adversely affect our business.

Climate Change. In response to concerns suggesting that emissions of certain gases, commonly referred to as "greenhouse gases" (including carbon dioxide and methane), may be contributing to warming of the earth's atmosphere, the EPA is taking steps that would result in the regulation of greenhouse gases as pollutants under the federal Clean Air Act.

In October 2009, the EPA promulgated its Mandatory Reporting Rule for greenhouse gases, which requires the monitoring and reporting of greenhouse gas emissions on an annual basis. All of our facilities operating combustion sources, such as engines or natural gas fractionation facilities, are subject to the greenhouse gas reporting requirements included in the October 2009 final rule. The first annual greenhouse gas emissions inventory for our affected facilities was filed by us in September 2011 and we continue to file the required annual reports. In November 2010 and further in December 2011, the EPA expanded the scope of the Mandatory Reporting Rule to include petroleum and natural gas pipeline systems, which applies the Mandatory Reporting Rule's requirements to, among other sources, fugitive and vented methane emissions from the oil and gas sector, including natural gas transmission compression. Our transmission compression facilities as well as gathering compressor stations with large amine treating capacities are also required to report under this expanded rule. The first reports for these facilities were due in 2012. Although the Mandatory Reporting Rule does not control greenhouse gas emission levels from any facilities, it has still caused us to incur monitoring and reporting costs for emissions that are subject to the rule.

After a series of regulatory actions finalized by the EPA between December 2009 and May 2010, greenhouse gases became pollutants "subject to regulation" under the Clean Air Act's Prevention of Significant Deterioration (PSD) air quality permit program for stationary sources, which in turn triggered permitting requirements under the Clean Air Act's Title V permitting program. In the "Tailoring Rule," the EPA promulgated regulatory thresholds for greenhouse gases that make PSD permitting requirements applicable to only relatively large sources of greenhouse gas emissions. As a result, new and modified stationary sources that emit greenhouse gases over statutory thresholds and the Tailoring Rule's regulatory thresholds must obtain a PSD permit setting forth Best Available Control Technology (BACT) for those emissions. The current Tailoring Rule threshold levels act to limit PSD permitting for greenhouse gases to only relatively large sources of greenhouse gas emissions, but the EPA has indicated that it may tighten the Tailoring Rule thresholds in the future, subjecting additional sources to PSD permitting requirements for greenhouse gases. The EPA has also proposed to regulate greenhouse gas emissions from certain electric generating units through the Clean Air Act's New Source Performance Standards (NSPS) program, and may expand greenhouse gas NSPS requirements to additional source categories in the future. Any new requirements could in the future affect our operations and our ability to obtain air permits for new or modified facilities.

The U.S. Congress has considered but to date has not enacted legislation to mandate reductions of greenhouse gas emissions, and almost half of the states, either individually or through multi-state regional initiatives, have already taken legal measures intended to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs.

Because regulation of greenhouse gas emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments in greenhouse gas initiatives may affect us and other companies operating in the oil and gas industry. In addition to these developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against greenhouse gas emissions sources, which may increase our litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with greenhouse gas emissions, we cannot predict the financial impact of related developments on us.

Federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which we conduct business could adversely affect the availability of, or demand for, the products we store, transport and process, 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 greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. We may be unable to recover any such lost revenues or increased costs in the rates we charge our customers, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have adverse effects on our business, financial position, results of operations and prospects.

Some scientific studies on climate change suggest that adverse weather events may become stronger or more frequent in the future in certain of the areas in which we operate, although the scientific studies are not unanimous. Due to their location, our operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems, while inland operations include areas subject to tornadoes. Our insurance may not cover all associated losses. We are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Hydraulic Fracturing and Wastewater. The Federal Water Pollution Control Act, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including NGL related wastes, into state waters or waters of the United States. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System, or NPDES, and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

We operate brine disposal wells that are regulated as Class II wells under the federal Safe Drinking Water Act (SDWA). The SDWA imposes requirements on owners and operators of Class II wells through the EPA's Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. Our brine disposal wells are also subject to comparable state laws and regulations, which in some cases are more stringent than requirements under the federal SDWA. Compliance with current and future laws and regulations regarding our brine disposal wells may impose substantial costs and restrictions on our brine disposal operations, as well as adversely affect demand for our brine disposal services. State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on our brine disposal operations.

It is common for our customers or suppliers to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is an important and commonly used process in the completion of wells by oil and gas producers. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states and localities have been initiated to require or make more stringent the permitting and other regulatory requirements for hydraulic fracturing operations. There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. Additional regulatory burdens in the future, whether federal, state or local, could increase the cost of or restrict the ability of our customers or suppliers to perform hydraulic fracturing. As a result, any increased federal, state or local regulation could reduce the volumes of natural gas that our customers move through our gathering systems which would materially adversely affect our revenues and results of operations.

Employee Safety. We are subject to the requirements of the Occupational Safety and Health Act, referred to as OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that 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 the OSHA requirements including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Pipeline Safety Regulations. Our pipelines are subject to regulation by the U.S. Department of Transportation (DOT). DOT's Pipeline Hazardous Material Safety Administration (PHMSA), acting through the Office of Pipeline Safety (OPS), administers the national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of pipeline facilities. The main bodies of safety regulations that cover our operations are set forth at 49 CFR, Parts 192 (covering pipelines that transport natural gas) and 195 (pipelines that transport crude oil, carbon dioxide, NGL and petroleum products). In addition to recordkeeping and reporting requirements, amendments to 49 CFR Part 192 and 195 created the Pipeline Integrity Management in High Consequence Areas (PIM) requiring operators of transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. In January 2012, the President signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 which increases potential penalties for pipeline safety violations, gives new rulemaking authority to DOT with respect to shut-off valves on transmission pipeline facilities constructed or entirely replaced after the rule is promulgated, requires DOT to revise incident notification guidance and imposes new records requirements on pipeline owners and operators. This legislation also requires DOT to study and report to Congress on other areas of pipeline safety, including expanding the reach of the integrity management regulations beyond high consequences areas, but restricts DOT from promulgating expanded integrity management rules during the review period and for a period following submission of its report to Congress unless the rulemaking is needed to address a present condition that poses a risk to public safety, property or the environment. PHMSA issued a final rule effective October 25, 2013 that implemented aspects of the new legislation. Among other things, the final rule increases the maximum civil penalties for violations of pipeline safety statutes or regulations, broadens PHMSA’s authority to submit information requests, and provides additional detail regarding PHMSA’s corrective action authority. Additionally, PHMSA issued an Advisory Bulletin in May 2012, which advised pipeline operators of anticipated changes in annual reporting requirements and that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipeline. A December 2012 PHMSA Advisory Bulletin provides further clarity on the reporting requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, describing a general requirement that pipeline owners or operators report an exceedance of the maximum allowable operating pressure or allowable build-up for pressure-limiting or control devices within five days of the date that the exceedance occurs. At the state level, several states have passed legislation or promulgated rulemaking dealing with pipeline safety. We believe that our pipeline operations are in substantial compliance with applicable PHMSA and state requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions.

Bayou Corne Sinkhole Incident. We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of these pipelines and our underground storage reservoirs located in Napoleonville, Louisiana.

Following the formation of the sinkhole, we and other pipeline operators in the area promptly undertook steps to depressurize and shut down our pipelines in the affected area. In particular, we took a section of our 36-inch diameter natural gas pipeline out of service. Our pipeline remains out of service, which has partially interrupted service to certain markets including the Mississippi River, but we worked with our customers to secure alternative natural gas supplies to minimize disruptions. In addition, we have identified a reroute for this pipeline outside of the affected areas. We are currently in the initial phase of constructing the replacement pipeline in our rerouted location and anticipate such construction will be completed during first half of 2014. We also implemented additional inspection and operational measures at our nearby underground facility. The damage to our business, including costs and loss of business has been considerable. For more information regarding the costs associated with this sinkhole, please see "Item 7. Management's Discussion and Analysis of Financial condition and Results of Operations—Liquidity and Capital Resources—Changes in Operations During 2013 and 2012."

The cause and full consequences of this sinkhole and the conditions giving rise thereto remain uncertain. In addition, any restrictions imposed by governmental agencies could negatively impact our assets. We are assessing the potential for recovering our losses from responsible parties and we are seeking recovery from our insurers. Our insurers, however, have denied our insurance claim for coverage and filed a declaratory judgment asking a court to determine that our insurance policy does not cover this damage. We have sued our insurers for breach of contract due to our insurers' refusal to pay our insurance claim for this damage. We cannot assure you that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

Office Facilities

We occupy approximately 108,500 square feet of space at our executive offices in Dallas, Texas under a lease expiring in August 2019, approximately 25,100 square feet of office space for our Louisiana operations in Houston, Texas with lease terms expiring in April 2023 and approximately 9,000 square feet of office space in Lafayette, Louisiana with lease terms expiring in January 2023.

Employees

As of December 31, 2013, we (through our subsidiaries) employed approximately 817 full-time employees. Approximately 218 of our employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. We are not party to any collective bargaining agreements and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Item 1A. *Risk Factors*

The following risk factors and all other information contained in this report should be considered carefully when evaluating us. These risk factors could affect our actual results. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occur, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included herein.

Risks Associated with the Contribution and the Mergers

We cannot assure you that we will complete the Contribution or, if completed, that such transaction will be beneficial to us.

We cannot assure you that we will complete the Contribution (as defined in "Item 1. Business - Business Development") or, if completed, that such transaction would achieve the desired benefits. The Contribution would involve numerous risks, including the failure to realize expected profitability or growth and an increase in collateral demands by our counterparties. Additionally, the failure to assimilate the Midstream Group Entities' assets into our existing assets would adversely affect our financial condition and results of operations. We will also be exposed to risks that are commonly associated with any acquisition, such as unanticipated liabilities and costs, some of which may be material, and diversion of management's attention. Moreover, the Midstream Group Entities' operations are subject to similar stringent environmental laws and regulations relating to releases of pollutants into the environment and environmental protection as are our existing pipelines and facilities, and thus our operation of those new assets would cause us to incur increased costs to maintain compliance with such laws and regulations.

If we consummate the Contribution and if any of these risks or unanticipated liabilities or costs were to materialize, any desired benefits of the Contribution may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted. Further, the failure to complete the Contribution could negatively impact the market price of our common units and our future business and financial results, and we may experience negative reactions from the financial markets and from our customers and employees.

If we complete the Contribution, we will expand our operations into new geographic areas.

The Contribution would, if ultimately consummated, significantly increase the size and scale of our business and expand the geographic areas in which we operate. Midstream Holdings operates its business in geographic regions in which we do not currently operate, including the Cana and Arkoma Woodford Shales in Oklahoma. In order to operate effectively in these new regions, we will need to understand the local market and regulatory environment and identify and retain certain employees from Devon who are familiar with these markets. If we are not successful in retaining these employees or operating in these new geographic areas, we may not be able to compete effectively in the new markets or fully realize the expected benefits of the Contribution.

Upon consummation of the Contribution, a significant portion of our operations will be located in the Barnett Shale, making us vulnerable to risks associated with having revenue-producing operations concentrated in a limited number of geographic areas.

If we complete the Contribution, our revenue-producing operations will be geographically concentrated in the Barnett Shale, causing us to be disproportionally exposed to risks associated with regional factors. The concentration of our operations in these regions also increases exposure to unexpected events that may occur in these regions such as natural disasters or labor difficulties. Any one of these events has the potential to have a relatively significant impact on our operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development within originally anticipated time frames. Any of these risks could have a material adverse effect on our financial condition and results of operations.

Upon Consummation of the Contribution, we will be dependent on Devon for substantially all of the natural gas that the Midstream Group Entities gather, process and transport, and a material decline in the volumes of natural gas that the Midstream Group Entities gather, process and transport for Devon would have a material adverse impact on our operating results and cash available for distribution.

The Midstream Group Entities rely on Devon for substantially all of their natural gas supply and do not expect to materially increase volumes from third-party producers in the near term. For the foreseeable future, we expect the profitability of the business of the Midstream Group Entities to remain substantially dependent on the volume of natural gas that Devon provides under commercial agreements to be entered into in connection with the closing of the Contribution. Upon the expiration or termination of these agreements, or in the event that the volume of natural gas purchased under these commercial agreements is reduced, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers.

Pending the completion of the Contribution, our business and operations could be materially adversely affected.

Under the terms of the Contribution Agreement, we are subject to certain restrictions on the conduct of our business prior to completing the transactions which may adversely affect our ability to execute certain of our business strategies, including our ability in certain cases to enter into contracts or incur capital expenditures to grow our business. Such limitations could negatively affect our business and operations prior to the completion of the Contribution. Furthermore, matters relating to the Contribution may require substantial commitments of time and resources by management, which could otherwise have been devoted to other opportunities that may have been beneficial to us.

We will incur substantial transaction-related costs in connection with the Contribution.

We expect to incur a number of non-recurring transaction-related costs associated with completing the Contribution, combining the operations of the Midstream Group Entities with our business and achieving desired synergies. These fees and costs will be substantial. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction-related costs over time. Thus, any net benefit may not be achieved in the near term, or at all.

The consummation of the Contribution and the Mergers would constitute a change of control of us.

The Partnership’s unitholders will have a reduced ownership and voting interest after the Contribution and will exercise less influence over management. Further, following the consummation of the Mergers, our general partner will be an indirect wholly-owned subsidiary of EnLink Midstream, a new public holding company that will be controlled by Devon. CEI stockholders currently have the right to vote in the election of the CEI board of directors and other matters affecting CEI. When the Mergers occur, each CEI shareholder that receives EnLink Midstream common units will become a unitholder of EnLink Midstream with a percentage ownership of the combined organization that is much smaller than such stockholder’s percentage ownership of CEI. EnLink Midstream unitholders are not entitled to elect the directors of EnLink Midstream’s managing member and have only limited voting rights on matters affecting Enlink Midstream's business and, therefore, limited ability to influence management’s decisions regarding our business. Because of its control of EnLink Midstream and our general partner, as well as due to its significant ownership of us following the Contribution, Devon will have the ability to influence our management, policies and business in a manner that may differ from our past practice.

The closing of the Contribution and the Mergers would trigger a mandatory repurchase offer under the indenture governing our 2018 Notes and, in certain circumstances, our 2022 Notes.

The closing of the Contribution and the Mergers will trigger a mandatory repurchase offer under the indenture governing our 2018 Notes. Completion of the Contribution and the Mergers also could trigger a mandatory repurchase offer under the indenture governing our 2022 Notes if, within 90 days of the consummation of the transactions, we experience a rating downgrade of the 2022 Notes by either Moody's or S&P. If we are unable to fund a repurchase of our 2018 Notes or, if necessary, our 2022 Notes, the counterparties may exercise their rights and remedies under the indentures, which could result in a default under our credit facility. Further, during the pendency of the proposed transactions, a decrease in Devon's perceived creditworthiness may have an adverse effect on our perceived creditworthiness, possibly resulting in a downgrade of credit ratings, tightening of credit under our credit facility, inability to borrow funds under our new credit facility or increasing our borrowing costs.

Risks Inherent In Our Business

Our substantial indebtedness could limit our flexibility and adversely affect our financial health.

We have a substantial amount of indebtedness. As of December 31, 2013, we had approximately $1.12 billion of indebtedness outstanding primarily comprised of $725.0 million (including $7.8 million of original issue discount) of senior unsecured notes due in 2018 and $250.0 million of senior unsecured notes due in 2022. As of December 31, 2013, there was $155.0 million of borrowing and $59.7 million in outstanding letters of credit under our existing credit facility leaving approximately $420.3 million available for future borrowings and letters of credit based on a borrowing capacity of $635.0 million. However, the financial covenants in our existing credit facility limit the amount of funds that we can borrow. As of December 31, 2013, based on the financial covenants in our existing credit facility, we could borrow approximately $207.1 million of additional funds.

Our substantial indebtedness could limit our flexibility and adversely affect our financial health. For example, it could:

- make us more vulnerable to general adverse economic and industry conditions;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow for operations and other purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared to competitors that may have proportionately less indebtedness.

In addition, our ability to make scheduled payments or to refinance our obligations depends on our successful financial and operating performance. We cannot assure you that our operating performance will generate sufficient cash flow or that our capital resources will be sufficient for payment of our debt obligations in the future. Our financial and operating performance, cash flow and capital resources depend upon prevailing economic conditions and certain financial, business and other factors, many of which are beyond our control.

If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to sell material assets or operations, obtain additional capital or restructure our debt. In the event that we are required to dispose of material assets or operations or restructure our debt to meet our debt service and other obligations, there cannot be any assurance as to the terms of any such transaction or how quickly any such transaction could be completed, if at all.

We may not be able to access new capital to fund our acquisition and growth strategies which could impair our ability to fund future capital needs and to grow.

Any limitations on our access to capital will impair our ability to execute our growth strategy, complete future acquisitions or future construction projects or other capital expenditures, take advantage of other business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations. In addition, if the cost of capital becomes too expensive, our ability to develop or acquire strategic and accretive assets will be limited. Further, our customers may increase collateral requirements from us, including letters of credit which reduce available borrowing capacity, or reduce the business they transact with us to reduce their credit exposure to us.

Due to our lack of asset diversification, adverse developments in our gathering, transmission, processing, crude oil, condensate, natural gas and NGL services businesses would materially impact our financial condition.

We rely exclusively on the revenues generated from our gathering, transmission, processing, crude oil, natural gas and condensate and NGL services businesses and as a result our financial condition depends upon prices of, and continued demand for, natural gas, NGLs and crude oil. Due to our lack of asset diversification, an adverse development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

We must continually compete for crude oil, condensate and natural gas supplies, and any decrease in supplies of such commodities could adversely affect our financial condition and results of operations.

In order to maintain or increase throughput levels in our natural gas gathering systems and asset utilization rates at our processing plants and to fulfill our current sales commitments, we must continually contract for new natural gas product. We may not be able to obtain additional contracts for crude oil, condensate, natural gas and NGL supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing supplies that are not committed to other systems and the level of drilling activity near our gathering systems. If we are unable to maintain or increase the volumes on our systems by accessing new supplies to offset the natural decline in reserves, our business and financial results could be materially, adversely affected. In addition, our future growth will depend in part upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our current supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil, condensate and natural gas reserves. Prolonged periods of low commodity prices may put downward pressure on future drilling activity which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of product available to our systems and assets. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying our processing plants. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in production or in the level of drilling activity in our principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position.

A substantial portion of our assets is connected or dependent on hydrocarbon reserves that will decline over time, and the cash flows associated with those assets will decline accordingly.

A substantial portion of our assets, including our gathering systems, is dedicated to certain hydrocarbon reserves and wells for which the production will naturally decline over time. Accordingly, our cash flows associated with these assets will also decline. If we are unable to access new supplies of hydrocarbons either by connecting additional reserves to our existing assets or by constructing or acquiring new assets that have access to additional hydrocarbon reserves, our cash flows may decline.

Growing our business by constructing new pipelines and processing facilities subjects us to risks that oil, natural gas or NGL supplies will not be available upon completion of the facilities and risks of construction delay and additional costs due to obtaining rights-of-way permits and complying with federal, state and local laws.

One of the ways we intend to grow our business is through the construction of additions to our existing gathering systems and construction of new pipelines and gathering and processing facilities. Generally, we may have only limited natural gas or NGL supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas and NGLs to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

Construction of our major development projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our operating results, liquidity and financial position.

We are engaged in the planning and construction of several major development projects, some of which will take a number of months before commercial operation, such as our Cajun-Sibon expansion project and the Bearkat processing facility project. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, complying with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our business, financial condition, results of operations and liquidity. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and capital position could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

We typically do not obtain independent evaluations of hydrocarbon reserves; therefore, volumes we service in the future could be less than we anticipate.

We typically do not obtain independent evaluations of hydrocarbon reserves connected to our gathering systems or that we otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves serviced by our assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than we anticipate and we are unable to secure additional sources, then the volumes transported on our gathering systems or that we otherwise service in the future could be less than anticipated. A decline in the volumes could have a material adverse effect on our results of operations and financial condition.

We may not be successful in balancing our purchases and sales.

We are a party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas or NGLs at prices that may exceed the prices received under the sales commitments. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

We have made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect our margins or even result in losses. For example, we are a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices on our NTPL and sell the gas into a different market area index. For the year ended December 31, 2013, we have recorded a loss of approximately$18.7 million on this contract, and we currently expect that we will record a loss of approximately $20.0 million to $24.0 million on this contract in 2014. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse. For additional information on this contract, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview."

Our profitability is dependent upon prices and market demand for oil, condensate, natural gas and NGLs, which are beyond our control and have been volatile.

We are subject to significant risks due to fluctuations in commodity prices. We are directly exposed to these risks primarily in the gas processing component of our business. For the year ended December 31, 2013, approximately 9% of our total gross operating margin was generated under percent of liquids contracts. Under these contracts we receive a fee in the form of a percentage of the liquids recovered and the producer bears all the cost of the natural gas shrink. Accordingly, our revenues under these contracts are directly impacted by the market price of NGLs.

We also realize processing gross operating margins under processing margin (margin) contracts. For the year endedDecember 31, 2013 approximately 5.6% of our total gross operating margin was generated under processing margin contracts. We have a number of processing margin contracts for activities at our Plaquemine, Gibson and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR. Our margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices. Although we do not currently have any processing margin contracts for our Blue Water and Eunice plants, we do have the opportunity to process liquids from wet gas flowing on the pipelines connected to these plants, as well as our other processing plants, when market pricing is favorable. Our Eunice and Blue Water plants are not profitable to operate unless market pricing is favorable.

We are also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of oil, condensate, natural gas and NGLs connected to or near our assets and on our margins for transportation between certain market centers. Low prices for these products will reduce the demand for our services and volumes on our systems.

In the past, the prices of oil, condensate, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2013 ranged from a high of $110.53 per Bbl in September 2013 to a low of $86.68 per Bbl in April 2013. Weighted average NGL prices in 2013 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a high of $1.09 per gallon in September 2013 to a low of $0.84 per gallon in June 2013. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2013 ranged from a high of $4.52 per MMBtu in December 2013 to a low of $3.08 per MMBtu in January 2013.

The markets and prices for oil, condensate, natural gas and NGLs depend upon factors beyond our control. These factors include the supply and demand for oil, condensate, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil, condensate, and natural gas production;
- technology, including improved production techniques (particularly with respect to shale development);
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil, natural gas and NGLs;
- international demand for oil and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation, including the regulation of "greenhouse gases."

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, crude oil and condensate we gather and process. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in "Item 7A. Quantitative and Qualitative Disclosure about Market Risk." Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income. For a discussion of our risk management activities, please read "Item 7A. Quantitative and Qualitative Disclosure about Market Risk."

We are vulnerable to operational, regulatory and other risks due to our concentration of assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

Our operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because we have a significant portion of our assets located in these two areas. Our concentration of activity in Louisiana and the Gulf of Mexico makes us more vulnerable than many of our competitors to the risks associated with these areas, including:

- adverse weather conditions, including hurricanes and tropical storms;
- delays or decreases in production, the availability of equipment, facilities or services; and
- changes in the regulatory environment.

Because a significant portion of our operations could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other midstream companies that have operations in more diversified geographic areas.

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

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services. Our NGL products and the demand for these products are affected as follows:

- *Ethane.* Ethane is typically supplied as purity ethane or as part of ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.

- *Propane.* Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of warmer-than-normal weather.

- *Normal Butane.* Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.

- *Isobutane.* Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

- *Natural Gasoline.* Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect demand for the services we provide as well as NGL prices, which would negatively impact our results of operations and financial condition.

We expect to encounter significant competition in any new geographic areas into which we seek to expand, and our ability to enter such markets may be limited.

If we expand our operations into new geographic areas, we expect to encounter significant competition for natural gas, condensate, NGLs and crude oil supplies and markets. Competitors in these new markets will include companies larger than us, which have both lower cost of capital and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, we may not be able to successfully develop acquired assets and markets located in new geographic areas and our results of operations could be adversely affected.

The terms of our credit facility and indentures may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

Our credit agreement governing our existing credit facility and the indentures governing our senior notes contain, and our new credit facility and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. Our existing debt agreements include covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness or issue preferred stock;

- pay dividends on our equity securities or redeem, repurchase or retire our equity securities or subordinated indebtedness;

- make investments;

- pay dividends or other distributions by our subsidiaries;
- engage in transactions with our affiliates;
- sell assets, including equity securities of our subsidiaries;
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase certain debt;
- make certain acquisitions;
- transfer assets;
- enter into sale and lease back transactions;
- amend our partnership agreement;
- make certain capital expenditures; and
- change business activities we conduct.

In addition, our credit facility requires us to satisfy and maintain specified financial ratios and other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under our credit facility and indentures. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If we are unable to repay the accelerated debt under our existing credit facility, the lenders under our existing credit facility could proceed against the collateral granted to them to secure that indebtedness. We have pledged substantially all of our assets as collateral under our existing credit facility. If indebtedness under our credit facility or indentures is accelerated, there can be no assurance that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

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

We do not own most of the land on which our pipelines and compression facilities are located, 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 leases or if such rights-of-way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce our revenue.

We offer pipeline, truck, rail and barge services. Significant delays, inclement weather or increased costs affecting these transportation methods could materially affect our operations and earnings.

We offer pipeline, truck, rail and barge services. The costs of conducting these services could be negatively affected by factors outside of our control, including rail service interruptions, new laws and regulations, rate increases, tariffs, rising fuel costs or capacity constraints. Inclement weather, including hurricanes, tornadoes, snow, ice and other weather events, can negatively impact our distribution network. In addition, rail, truck or barge accidents involving the transportation of hazardous materials could result in significant claims arising from personal injury, property damage and environmental penalties and remediation.

We could experience increased severity or frequency of trucking accidents and other claims.

Potential liability associated with accidents in the trucking industry is severe and occurrences are unpredictable. A material increase in the frequency or severity of accidents or workers' compensation claims or the unfavorable development of existing claims could be expected to materially adversely affect our results of operations. In the event that accidents occur, we may be unable to obtain desired contractual indemnities, and our insurance may be inadequate in certain cases. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses.

Changes in trucking regulations may increase our costs and negatively impact our results of operations.

Our trucking services are subject to regulation as a motor carrier by the United States Department of Transportation and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. These regulatory authorities exercise broad powers over our trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing and specifications and insurance requirements. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact our operations and affect the economics of the industry by requiring changes in operating practices or by changing the demand for or the cost of providing trucking services. Some of these possible changes include increasingly stringent fuel emission limits, changes in the regulations that govern the amount of time a driver may drive or work in any specific period, limits on vehicle weight and size and other matters, including safety requirements.

If we do not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with our asset base, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in cash generated from operations on a per unit basis. If we are unable to make accretive acquisitions either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors, then our future growth and our ability to increase distributions will be limited.

From time to time, we may evaluate and seek to acquire assets or businesses that we believe complement our existing business and related assets. We may acquire assets or businesses that we plan to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- the coordination of geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management's assessment of these risks is inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect our operations and cash flows. If we consummate any future acquisition, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We may not be able to retain existing customers or acquire new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other midstream service providers, and the price of, and demand for, crude oil, condensate, NGLs and natural gas in the markets we serve. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

In particular, our ability to renew or replace our existing contracts with industrial end-users and utilities impacts our profitability. For the year ended December 31, 2013, approximately 51% of our sales of gas that was transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities may be reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price.

We depend on certain key customers, and the loss of any of our key customers could adversely affect our financial results.

We derive a significant portion of our revenues from contracts with key customers. To the extent that these and other customers may reduce volumes of natural gas purchased or transported under existing contracts, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers. In addition, certain agreements with key customers provide for minimum volumes of natural gas, NGLs or natural gas services that require the customer to transport, process or purchase until the expiration of the term of the applicable agreement, subject to certain force majeure provisions. Customers may default on their obligations to transport, process or purchase the minimum volumes of natural gas, NGLs or natural gas services required under the applicable agreements.

We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could have an adverse effect on our financial condition and results of operations.

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A portion of our suppliers' and customers' natural gas production is developed from unconventional sources, such as deep gas shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Hydraulic fracturing activities are generally regulated by state oil and gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has released draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where EPA is the permitting authority. In addition, legislation has been proposed, but not passed that would provide for federal regulation of hydraulic fracturing and require disclosure of the chemicals used in the hydraulic-fracturing process. State legislatures and agencies are also enacting legislation and promulgating rules to regulate hydraulic fracturing and require disclosure of hydraulic fracturing chemicals.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. In addition to the EPA, other federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

We cannot predict whether any additional legislation or regulations will be enacted and, if so, what the provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process constraints for our suppliers and customers that could reduce the volumes of natural gas that move through our gathering systems which could materially adversely affect our revenue and results of operations.

Transportation on certain of our natural gas pipelines is subject to federal and state rate and service regulation, which could limit the revenues we collect from our customers and adversely affect the cash available for distribution to our

unitholders. The imposition of regulation on our currently unregulated natural gas pipelines also could increase our operating costs and adversely affect the cash available for distribution to our unitholders.

The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC regulation under Section 311 of the Natural Gas Policy Act and the rules and regulations promulgated under that statute. Under these regulations, we are required to justify our rates for interstate transportation service on a cost-of-service basis every five years. Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that our rates for Section 311 transportation service or intrastate transportation service should be lowered, our business could be adversely affected.

Our natural gas gathering and processing activities generally are exempt from FERC regulation under the Natural Gas Act. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Other state and local regulations also affect our business. We are subject to some ratable take and common purchaser statutes in the states where we operate. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.

Transportation on our liquids pipelines is subject to federal rate and service regulation, which could limit the revenues we collect from our customers and adversely affect the cash available for distribution to our unitholders.

Our liquids transportation pipelines in the Ohio River Valley and the Cajun-Sibon NGL pipeline, which went into service in November 2013, are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates and terms and conditions of service for interstate service on liquids pipelines be just, reasonable and not unduly discriminatory or preferential. The ICA also requires that such rates and terms and conditions be set forth in tariffs filed with FERC. The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rates are unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rates during the term of the investigation. 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. Under certain circumstances, FERC could limit our ability to set rates based on our costs or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change our terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As we acquire, construct and operate new liquids assets and expand our liquids transportation business segment, the classification and regulation of our liquids transportation services are subject to ongoing assessment and change based on the services we provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC, which could increase our operating costs, decrease our rates and adversely affect our business.

We may incur significant costs and liabilities resulting from compliance with pipeline safety regulations.

The states in which we conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968. These standards only apply to certain natural gas gathering lines based on the gathering line's operating pressure and proximity to people. Because of their pressure and location, substantial portions of our gathering facilities are not regulated under that statute. The gathering line exemptions, however, may be revised in the future and place more of our gathering facilities under jurisdiction of the DOT. Nonetheless, our natural gas transmission pipelines are subject to regulation by the DOT. In response to pipeline accidents in other parts of the country, Congress and the DOT, through PHMSA, have passed or are considering heightened pipeline safety requirements that may be applicable to gathering lines. As a result, our pipeline facilities are subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which reauthorized funding for federal safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

At the state level, several states have passed legislation or promulgated rulemaking addressing pipeline safety. Compliance with pipeline integrity and other pipeline safety regulations issued by DOT or those issued by the Texas Railroad Commission, or TRRC, could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately at $1.6 million, $1.4 million, and $1.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $2.1 million during 2014. If our pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then we may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced maximum allowable operating pressure, the cost of which cannot be estimated at this time.

In addition, our liquids transportation pipelines are subject to regulation by the DOT, through PHMSA, pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended by the Pipeline Safety Improvement Act of 2002, and reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. PHMSA has adopted regulations requiring hazardous liquid pipeline operators to develop and implement integrity management programs for pipeline segments that, in the event of a leak or rupture, could affect “high consequence areas,” such as high population areas, areas that are sources of drinking water, 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.

Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. As our operations continue to expand into and around urban or more populated areas, such as the Barnett Shale, we may incur additional expenses to mitigate noise, odor and light that may be emitted in our operations and expenses related to the appearance of our facilities. Municipal and other local or state regulations are imposing various obligations including, among other things, regulating the location of our facilities, imposing limitations on the noise levels of our facilities and requiring certain other improvements that increase the cost of our facilities. We are also subject to claims by neighboring landowners for nuisance related to the construction and operation of our facilities, which could subject us to damages for declines in neighboring property values due to our construction and operation of facilities.

Failure to comply with existing or new environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment may cause us to incur significant costs and liabilities.

Many of the operations and activities of our gathering systems, processing plants, fractionators, brine disposal operations and other facilities are subject to significant federal, state and local environmental laws and regulations. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from our facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for treatment or disposal. Various governmental authorities 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. Strict, joint and several liability may be incurred under these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties near our facilities or upon or through which our gathering systems traverse, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations for releases of contaminants or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in our business due to our handling of natural gas, crude oil and other petroleum substances, our brine disposal operations, air emissions related to our operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. For example, we operate brine disposal wells in Ohio and West Virginia and may gather brine from surrounding states. These wells are regulated under the federal Safe Drinking Water Act (SDWA) as Class II wells and under state laws. State laws and regulations that govern these operations can be more stringent than the federal SDWA, such as the Ohio Department of Natural Resources rules which took effect October 1, 2012. These rules imposed new, more stringent environmentally responsible standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state of the art technology. They apply to new disposal wells and, as applicable, to existing wells. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us.

In addition, state and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on our brine disposal operations.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental laws or regulations, including, for example, legislation relating to the control of greenhouse gas emissions, or changes in existing environmental laws or regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability. Changes in laws or regulations could also limit our production or the operation of our assets or adversely affect our ability to comply with applicable legal requirements or the demand for crude oil, brine disposal services or natural gas, which could adversely affect our business and our profitability.

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

On April 17, 2012, the EPA issued final rules under the Clean Air Act that became effective on October 15, 2012. Among other things, these rules require additional emissions controls for natural gas and NGLs production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. Moreover, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require a number of modifications to our operations and our natural gas exploration and production suppliers' and customers' operations, including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for our services. The rules are subject to an ongoing legal challenge brought by various parties, including environmental groups and industry, and the EPA has indicated that it may revise the rules. Any such revisions could affect our operations, as well as the operations of our suppliers and customers.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services we provide.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allowed the EPA to proceed with the adoption and implementation of regulations restricting emissions of GHGs under existing provisions of the federal Clean Air Act. Since 2011, the EPA has required stationary sources that emit GHGs above regulatory and statutory thresholds to obtain a Prevention of Significant Deterioration permit. Moreover, on October 30, 2009, the EPA published a "Mandatory Reporting of Greenhouse Gases" final rule that established a comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. The Mandatory Reporting Rule was expanded by a rule promulgated on November 30, 2010 to include owners and operators of onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Reporting emissions from such onshore activities is required on an annual basis. The first reports were due in 2012 for emissions occurring in 2011. Additionally, the EPA has proposed to regulate greenhouse gas emissions from certain electric generating units under the Clean Air Act's New Source Performance Standards ("NSPS") program. The EPA may propose to regulate additional source categories under the NSPS program in the future.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, and almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations, could adversely affect our performance of operations in the absence of any permits that may be required to regulate emission of GHGs or could adversely affect demand for the natural gas we gather, process or otherwise handle in connection with our services.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

Our operations are subject to the many hazards inherent in the gathering, compressing, processing, transporting, fractionating, disposal and storage of natural gas, NGLs, condensate, crude oil and brine, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons;
- induced seismicity;
- rail accidents, barge accidents and truck accidents; and
- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we do not have business interruption insurance or any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

The adoption of derivatives legislation by the United States Congress and promulgation of related regulations could have an adverse effect on our ability to hedge risks associated with our business.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter (“OTC”) derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

Our operations expose us to fluctuations in commodity prices, and our credit facility exposes us to fluctuations in interest rates. We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. As of December 31, 2013, we have hedged only portions of our expected exposures to commodity price risk. In addition, to the extent we hedge our commodity price risk using swap instruments, we will forego the benefits of favorable changes in commodity prices. Although we do not currently have any financial instruments to eliminate our exposure to interest rate fluctuations, we may use financial instruments in the future to offset our exposure to interest rate fluctuations.

Even though monitored by management, our hedging activities may fail to protect us and could reduce our earnings and cash flow. Our hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors:

- hedging can be expensive, particularly during periods of volatile prices;
- our counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and
- available hedges may not correspond directly with the risks against which we seek protection. For example:
  - the duration of a hedge may not match the duration of the risk against which we seek protection;
  - variations in the index we use to price a commodity hedge may not adequately correlate with variations in the index we use to sell the physical commodity (known as basis risk); and
  - we may not produce or process sufficient volumes to cover swap arrangements we enter into for a given period. If our actual volumes are lower than the volumes we estimated when entering into a swap for the period, we might be forced to satisfy all or a portion of our derivative obligation without the benefit of cash flow from our sale or purchase of the underlying physical commodity, which could adversely affect our liquidity.

Our financial statements may reflect gains or losses arising from exposure to commodity prices for which we are unable to enter into fully effective hedges. In addition, the standards for cash flow hedge accounting are rigorous. Even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective cash flow hedges for accounting purposes. Our earnings could be subject to increased volatility to the extent our derivatives do not continue to qualify as cash flow hedges and, if we assume derivatives as part of an acquisition, to the extent we cannot obtain or choose not to seek cash flow hedge accounting for the derivatives we assume. Please read "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" for a summary of our hedging activities.

Our success depends on key members of our management, the loss or replacement of whom could disrupt our business operations.

We depend on the continued employment and performance of the officers of our general partner and key operational personnel. Our general partner has entered into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any "key man" life insurance for any officers.

A default under CEI’s Subsidiary’s credit facility could have an adverse effect on the price of our common units and could result in a change of control of our general partner.

A subsidiary of CEI, has entered into a credit facility that is initially secured by a first priority lien on 10,700,000 of our common units and that is guaranteed by CEI. A decline in the price of our common units could require CEI to pledge additional common units or to sell common units that it owns (directly or indirectly) in an expedited manner. Although we are not a party to this credit facility, if a default under such credit facility were to occur, the lenders could foreclose on the pledged units and/or CEI may be forced to sell its assets, including its interest in our general partner or the remaining common units owned by it, to fund any repayment obligations. Any such sale of our common units that it owns (directly or indirectly) could have an adverse effect on the market price of our common units. In addition, any sale by CEI of our general partner would allow the new owner of our general partner to replace the board of directors and officers of our general partner with its own choices and to control the decisions taken by the board of directors and officers. Moreover, any change of control of our general partner (i) would permit the lenders under our credit facility to declare all amounts thereunder immediately due and payable and (ii) may permit the holders of the two outstanding series of our senior unsecured notes to require us to repurchase such notes. If any such event occurs, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders.

The credit and risk profile of CEI could adversely affect our risk profile, which could increase our borrowing costs, hinder our ability to raise capital or impact future credit ratings.

The credit and business risk profiles of CEI may factor into the credit evaluations of us. This is because our general partner can exercise significant influence over our business activities, including cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered in credit evaluations of us is the financial condition of CEI or its subsidiaries, including the degree of their financial leverage and their dependence on cash flow from us to service their indebtedness.

Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us, our general partner, CEI and its subsidiaries, our credit ratings and business risk profile could be adversely affected if the credit ratings and risk profiles of our general partner, CEI or its subsidiaries were viewed as substantially lower or more risky than ours.

Risks Inherent in an Investment in the Partnership

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on our units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of our general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, levels of production of and demand for oil, natural gas, condensate and NGLs;
- the volume of natural gas we gather, compress, process, transport and sell, the volume of NGLs we process or fractionate and sell, the volume of crude oil we handle at our crude terminals, the volume of crude oil we gather, transport, purchase and sell and the volumes of brine we dispose;
- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- our ability to make borrowings under our credit facility to pay distributions;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- general and administrative expenses;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

Crosstex Energy, Inc., or CEI, controls our general partner and owned a 15.0% fully diluted limited partner interest in us as of December 31, 2013. Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor its own interests.

As of December 31, 2013, CEI indirectly owned an aggregate fully diluted limited partner interest of approximately 15.0% in us. In addition, CEI owns and controls our general partner. Due to its control of our general partner and the size of its limited partner interest in us, CEI effectively controls all limited partnership decisions, including any decisions related to the removal of our general partner. Conflicts of interest may arise in the future between CEI and its affiliates, including our general partner, on the one hand, and our partnership, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates over our interests. These conflicts include, among others, the following situations:

Conflicts Relating to Control

- our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without these limitations, constitute breaches of fiduciary duty by our general partner;
- in resolving conflicts of interest, our general partner is allowed to take into account the interests of parties in addition to unitholders, which has the effect of limiting its fiduciary duties to the unitholders;
- our general partner's affiliates may engage in limited competition with us;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- in some instances our general partner may cause us to borrow funds from affiliates of the general partner or from third parties in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions; and
- our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution.

Conflicts Relating to Costs

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner interests and reserves;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us; and
- our general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

Our unitholders have no right to elect our general partner or the directors of our general partner and have limited ability to remove our general partner.

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 of directors of our general partner and have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The general partner generally may not be removed except upon the vote of the holders of 66 2/3% of the outstanding units voting together as a single class. Affiliates of the general partner controlled approximately 15.0% of all the limited partner units as December 31, 2013.

In addition, unitholders' voting rights are further restricted by the partnership agreement. It provides that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner, cannot be voted on any matter. In addition, the partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, it will be more difficult for a third party to acquire our partnership without first negotiating such a purchase with our general partner and, as a result, our unitholders are less likely to receive a takeover premium.

Cost reimbursements due to our general partner may be substantial and will reduce the cash available for distribution to our unitholders.

Prior to making any distributions on the units, we reimburse our general partner and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to make distributions to our unitholders. Our general partner has sole discretion to determine the amount of these expenses.

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

The 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, there is no restriction in the partnership agreement on the ability of the owner of the general partner from transferring its ownership interest in the general partner to a third party. The new owner of the general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and to control the decisions taken by the board of directors and officers.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to our unitholders.

Our partnership agreement contains provisions that reduce the remedies available to our unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to our unitholders. The partnership agreement also restricts the remedies available to our unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. If you own a unit, you will be treated as having consented to the various actions contemplated in the partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary duties under applicable state law.

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

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. The issuance of additional limited partner interests will have the following effects:

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

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

If at any time our general partner and its affiliates own more than 80.0% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their units.

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

Our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the "control" of our business, to the extent that a person who has transacted business with the Partnership reasonably believes, based on our unitholders' conduct, that our unitholders are a general partner. Our general partner generally has unlimited liability for the obligations of the Partnership, such as its debts and environmental liabilities, except for those contractual obligations of the Partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of that section may be liable to the limited partnership for the amount of the distribution for a period of three years from the date of the distribution. 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.

Tax Risks to Our Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity level taxation by individual states. If the IRS treats us as a corporation or we become subject to entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to you.

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay additional tax on our income at corporate rates of up to 35.0% (under the law as of the date of this report) and we would probably pay state income taxes as well. In addition, distributions to unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses, or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to 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 the unitholders and thus would likely result in a material reduction in the value of the common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, members of Congress have considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the legislation considered would not have appeared to affect our tax treatment, we are unable to predict whether any such change or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. At the state level, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 1.0% of our gross income apportioned to Texas in the prior year. If federal income tax or material amounts of additional state tax were to be imposed on us, the cash available for distribution to unitholders could be reduced and/or the value of an investment in our common units would be adversely impacted. 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 decreased to reflect the impact of that law on us.

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

We have not requested any 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 our counsel's conclusions expressed in this annual report 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 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 common units and the prices at which our common units trade. In addition, our costs of any contest with the IRS will be borne by us and therefore indirectly by our unitholders and our general partner since such costs will reduce the amount of cash available for distribution by us.

Unitholders may be required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, they will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even the tax liability that results from that income.

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

Unitholders who sell common units will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of the unitholders' allocable share of total net taxable income decrease the unitholder's tax basis in his or her units, the amount, if any, of such prior excess distributions with respect to the units sold by the unitholder, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received 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 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 units may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), pension plans, 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 qualified retirement plans, will be unrelated business 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 federal income tax returns and generally pay tax on their share of our taxable income. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units.

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

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

The sale or exchange of 50% or more of our capital and profits interests within a 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year if the termination occurs on a day other than December 31. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder who has adopted 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 such unitholder's taxable income for the year of termination. Our termination would cause us to be treated as a new partnership for tax purposes for which we must make new tax elections, and we could be subject to penalties if we were to fail to recognize and properly report on our tax return that a termination occurred.

The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated its partnership makes a request for publicly traded partnership technical termination relief and such relief is granted by the IRS then, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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 been considering substantive changes to the definition of qualifying income and the treatment of certain types of income earned from profits interests in partnerships. While these specific proposals would not appear to affect our treatment as a partnership, 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 common units.

We will 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 unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

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

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

Tax Treatment of Income Earned Through C Corporation Subsidiaries

A material portion of our taxable income is earned through C corporation subsidiaries. Such C corporation subsidiaries are subject to federal income tax on their taxable 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, on their taxable income. Any such entity level taxes will reduce the cash available for distribution to our unitholders. Distributions from any such C corporation subsidiary will generally be taxed again to unitholders as dividend income to the extent of current and accumulated earnings and profits of such subsidiary. As of January 1, 2014, the maximum federal income tax rate applicable to such dividend income which is allocable to individuals is 20%. An individual unitholder's share of dividend and interest income from our C corporation subsidiaries would constitute portfolio income that could not be offset by the unitholder's share of our other losses or deductions.

As a result of investing in our common units, you will likely be subject to state and local taxes and return filing or withholding requirements in jurisdictions where you do not live.

In addition to federal income taxes, you 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 do business or own property. You will likely be required to file state and local tax returns and pay state and local income taxes in some or all of the various jurisdictions in which we do business or own property and you may be subject to penalties for failure to comply with those requirements. We own property or conduct business in a number of states, most of which currently impose a state income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may do business or own property in other states that impose an income tax. It is our unitholders' responsibility to file all federal, state, local, and foreign 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. Our counsel has not rendered an opinion on the state, local, or foreign tax consequences of owning our common units.

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

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

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

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common 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 modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Compliance with and changes in tax law could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. *Unresolved Staff Comments*

We do not have any unresolved staff comments.

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 pipeline was built was purchased in fee. Our processing plants are located on land that we lease or own in fee.

We believe that we have satisfactory title to all of our rights-of-way and land assets. Title to these assets may be subject to encumbrances or defects. We believe that none of such encumbrances or defects should materially detract from the value of our assets or from our interest in these assets or should materially interfere with their use in the operation of the business.

Item 3. *Legal Proceedings*

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we may be a defendant in various legal proceedings and litigation arising in the ordinary course of business, including litigation on disputes related to contracts, property use or damage and personal injury. Additionally, as we continue to expand operations into more urban, populated areas, such as the Barnett Shale, we may see an increase in claims brought by area landowners, such as nuisance claims and other claims based on property rights. Except as otherwise set forth herein, we do not believe that any pending or threatened claim or dispute is material to our financial results on our operations. We maintain insurance policies with insurers in amounts and with coverage and deductibles as our general partner believes are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

At times, our gas-utility and common carrier subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain. As a result, we (or our subsidiaries) are party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value, if any, of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations or financial condition.

From time to time, owners of property located near our processing facilities or compression facilities file lawsuits against us. These suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. We have appealed the matter and have posted a bond to secure the judgment pending its resolution. We have accrued a $2.0 million liability related to this matter. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations or financial condition.

Item 4. *Mine Safety Disclosures*

Not applicable.

PART II

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

Our common units are listed on The NASDAQ Global Select Market under the symbol "XTEX". On February 19, 2014, the closing market price for the common units was $29.94 per unit and there were approximately 26,763 record holders and beneficial owners (held in street name) of our common units. For equity compensation plan information, see discussion under "Item. 12 Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters—Equity Compensation Plan Information."

The following table shows (i) the high and low closing sales prices per common unit, as reported by The NASDAQ Global Select Market and (ii) the amount of our quarterly distributions for the periods indicated.

	Range		Cash Distribution
	High	Low	Declared Per Unit(a)
2013:			
Quarter Ended December 31	$ 29.50	$ 19.29	$ 0.36
Quarter Ended September 30	22.05	18.22	0.34
Quarter Ended June 30	21.89	17.63	0.33
Quarter Ended March 31	18.58	14.70	0.33
2012:			
Quarter Ended December 31	$ 16.40	$ 13.51	$ 0.33
Quarter Ended September 30	17.01	13.91	0.33
Quarter Ended June 30	18.00	14.58	0.33
Quarter Ended March 31	17.27	16.40	0.33

(a) For each quarter in which a distribution was paid, an identical cash distribution was paid on all outstanding preferred units for first three quarters of 2012, and a distribution based on the same distribution rate was paid through the issuance of additional preferred units ("paid-in-kind") on all outstanding preferred units for the fourth quarter of 2012 and all of 2013.

Unless restricted by the terms of our credit facility, within 45 days after the end of each quarter, we will distribute all of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. Our available cash consists generally of all cash on hand at the end of the fiscal quarter, less reserves that our general partner determines are necessary to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;
- plus all cash on hand for the quarter resulting from working capital borrowings made after the end of the quarter on the date of determination of available cash.

The indentures governing our senior unsecured notes provide the ability to pay distributions if a minimum fixed charged coverage ratio is met and also provide baskets to make payments if such minimum is not met.

Our ability to distribute available cash is contractually restricted by the terms of our existing credit facility. Our credit facility contains covenants requiring us to maintain certain financial ratios. Under our existing credit facility, we are prohibited from making any distributions if the distribution would cause an event of default, or an event of default is existing, under our credit facility. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation—Description of Indebtedness."

Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Our distributions are made to our general partner based on its ownership interest with the remaining interest to unitholders, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Incentive distributions to our general partner increase to 13.0%, 23.0% and 48.0% based on incremental distribution thresholds as set forth in our partnership agreement.

On January 19, 2010, we issued approximately $125.0 million of Series A Convertible Preferred Units (the "preferred units") to an affiliate of Blackstone/GSO Capital Solutions under exemption Section 4(2) of the Securities Act of 1933, as amended (the "Securities Act"). The preferred units were convertible into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. Holders of the preferred units were entitled to receive quarterly cash distributions with a value equal to the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders. Such distributions were paid in cash during 2010 through the second quarter of 2012.

Beginning in the third quarter of 2012 through the fourth quarter of 2013, the quarterly distributions on the preferred units were paid-in-kind resulting in the issuance of 2,389,250 additional preferred units with the last distribution paid-in-kind on February 12, 2014. All future quarterly preferred unit quarterly distributions will be paid in cash.

We had the right to force conversion of the preferred units if (i) the daily volume weighted average trading price of the common units is greater than $12.75 per unit for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion, and (ii) the average trading volume of common units exceeds a specified number of common units (the “trading volume threshold”) for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion. On February 27, 2014, the board of directors of our general partner amended our partnership agreement to reduce the trading volume threshold from 250,000 common units to 215,000, and on that same date we delivered a notice of conversion of all outstanding preferred units.

For a discussion regarding our issuance of our senior unsecured notes, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Indebtedness."

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

The following table sets forth selected historical financial and operating data of Crosstex Energy, L.P. as of and for the dates and periods indicated. Financial and operating data related to the July 2012 acquisition of our ORV assets is included for the years ended December 31, 2013 and 2012. The selected historical financial data are derived from the audited consolidated financial statements of Crosstex Energy, L.P. and should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Crosstex Energy, L.P. Years Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Midstream	$ 1,943,239	$ 1,791,288	$ 2,013,942	$ 1,792,676	$ 1,583,551
Operating costs and expenses:					
Purchased gas, NGLs and crude oil	1,546,987	1,397,530	1,638,777	1,454,376	1,272,329
Operating expenses	150,346	130,882	111,778	105,060	110,394
General and administrative	68,061	61,308	52,801	48,414	59,854
(Gain) loss on sale of property	(1,055)	(342)	264	(13,881)	(666)
(Gain) loss on derivatives	2,304	1,006	7,776	9,100	(2,994)
Impairments	72,576	—	—	1,311	2,894
Depreciation and amortization	140,026	162,226	125,284	111,551	119,088
Total operating costs and expenses	1,979,245	1,752,610	1,936,680	1,715,931	1,560,899
Operating income (loss)	(36,006)	38,678	77,262	76,745	22,652
Other income (expense):					
Interest expense, net	(76,219)	(86,521)	(79,233)	(87,035)	(95,078)
Loss on extinguishment of debt	—	—	—	(14,713)	(4,669)
Equity in income of limited liability company	46	3,250	—	—	—
Other income	1,367	5,053	707	295	1,400
Total other expense	(74,806)	(78,218)	(78,526)	(101,453)	(98,347)
Loss from continuing operations before non-controlling interest and income taxes	(110,812)	(39,540)	(1,264)	(24,708)	(75,695)
Income tax provision	(2,337)	(725)	(1,126)	(1,121)	(1,790)
Loss from continuing operations, net of tax	(113,149)	(40,265)	(2,390)	(25,829)	(77,485)
Loss from discontinued operations, net of tax	—	—	—	—	(1,796)
Gain from sale of discontinued operations, net of tax	—	—	—	—	183,747
Discontinued operations	—	—	—	—	181,951

	Crosstex Energy, L.P. Years Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands, except per unit data)				
Net income (loss)	(113,149)	(40,265)	(2,390)	(25,829)	104,466
Less: Net income (loss) from continuing operations attributable to the non-controlling interest	—	(163)	(48)	19	60
Net income (loss) attributable to Crosstex Energy, L.P.	$ (113,149)	$ (40,102)	$ (2,342)	$ (25,848)	$ 104,406
Preferred interest in net income attributable to Crosstex Energy, L.P.	$ 35,977	$ 20,779	$ 18,088	$ 13,750	$ —
Beneficial conversion feature attributable to preferred units	$ —	$ —	$ —	$ 22,279	$ —
General partner interest in net income (loss)	$ (2,721)	$ (534)	$ (732)	$ (4,371)	$ (819)
Limited partners' interest in net income (loss) attributable to Crosstex Energy, L.P.	$ (146,405)	$ (60,347)	$ (19,698)	$ (57,506)	$ 105,225
Income (loss) per unit from continuing operations:					
Basic and diluted common unit	$ (1.71)	$ (1.01)	$ (0.38)	$ (1.12)	$ (2.18)
Senior subordinated unit	$ —	$ —	$ —	$ —	$ 8.85
Distributions declared per limited partner unit	$ 1.36	$ 1.32	$ 1.23	$ 0.51	$ —
Balance Sheet Data (end of period):					
Working capital deficit	$ (16,805)	$ (18,323)	$ (22,596)	$ (17,640)	$ (50,320)
Property and equipment, net	1,854,249	1,471,248	1,241,901	1,215,104	1,279,060
Total assets	2,759,336	2,422,589	1,955,331	1,984,940	2,069,181
Long-term debt (including current maturities)	1,122,202	1,036,305	798,409	718,570	873,702
Capital lease obligations (including current maturities)	21,988	25,257	28,367	31,327	23,799
Partners' equity including non- controlling interest	1,206,692	1,009,081	900,459	976,936	893,282
Cash Flow Data:					
Net cash flow provided by (used in)(1):					
Operating activities	$ 95,155	$ 103,896	$ 143,572	$ 87,187	$ 80,978
Investing activities	(481,137)	(490,283)	(132,094)	14,638	379,874
Financing activities	385,915	362,368	(5,032)	(84,907)	(461,709)
Non-GAAP Financial Measures:					
Gross operating margin(2)	$ 396,252	$ 393,758	$ 375,165	$ 338,300	$ 311,222
Adjusted EBITDA(3)(4)	$ 214,876	$ 214,089	$ 214,028	$ 186,880	$ 158,682
Operating Data:					
Pipeline throughput (MMBtu/d)	1,515,000	1,943,000	2,037,000	1,971,000	2,040,000
Natural gas processed (MMBtu/d)	1,036,000	1,350,000	1,325,000	1,366,000	1,235,000
NGL Fractionation (Gals/d) (5)	1,473,000	1,359,000	1,109,000	922,000	686,000
Crude Oil Handling (BBls/d)(6)	12,000	11,800	—	—	—
Brine Disposal (Bbls/d)(6)	7,000	7,800	—	—	—

(1) Cash flow data includes cash flows from discontinued operations.

(2) Gross operating margin is defined as revenue minus cost of purchased gas, NGLs and crude oil.

(3) Adjusted EBITDA is defined as net income plus interest expense, provision for income taxes and depreciation and amortization expense, impairments, stock-based compensation, loss on extinguishment of debt, (gain) loss on noncash derivatives, transaction costs associated with successful transactions, distribution from limited liability company, non-controlling interest, certain severance and exit expenses and accrued expense of legal judgment under appeal; less (income) loss from discontinued operations, gain (loss) on sale of property and equipty in income of limited liability company.

(4) Adjusted EBITDA for the year ended December 31, 2009 is from continuing operations.

(5) Includes Cajun Sibon NGL volumes, which are transported to our southern Louisiana assets for fractionation.

(6) Crude oil handling and brine disposal volumes for the year ended December 31, 2012 include a daily average for July 2012 through December 2012, the six-month period these assets were operated by us.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures in this report: adjusted EBITDA and gross operating margin.

We define adjusted EBITDA as net income plus interest expense, provision for income taxes and depreciation and amortization expense, impairments, stock-based compensation, loss on extinguishment of debt, (gain) loss on noncash derivatives, transaction costs associated with successful transactions, distribution from limited liability company, non-controlling interest, certain severance and exit expenses; and accrued legal judgment under appeal; less (income) loss from discontinued operations, gain (loss) on sale of property and equity in income of limited liability company. Our adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our general partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Adjusted EBITDA is one of the critical inputs into the financial covenants within our credit facility. The rates we pay for borrowings under our existing credit facility are determined by the ratio of our debt to adjusted EBITDA.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Our adjusted EBITDA may not be comparable to similarly titled measures of other companies because other entities may not calculate adjusted EBITDA operations in the same manner.

Adjusted EBITDA does not include interest expense, income taxes or depreciation and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following table provides a reconciliation of adjusted EBITDA to net income (loss):

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Net income (loss) attributable to Crosstex Energy, L.P.	$ (113,149)	$ (40,102)	$ (2,342)	$ (25,848)	$ 104,406
Interest expense	76,219	86,521	79,233	87,035	95,078
Depreciation and amortization	140,026	162,226	125,284	111,551	119,088
Impairment	72,576	—	—	1,311	2,894
Equity in income of limited liability company	(46)	(3,250)	—	—	—
Loss on extinguishment of debt	—	—	—	14,713	4,669
Distribution from limited liability company	17,468	—	—	—	—
(Gain) loss on sale of property	(1,055)	(342)	264	(13,881)	(666)
Stock-based compensation	14,170	9,207	7,308	9,276	8,742
Loss from discontinued operations, net of tax	—	—	—	—	1,796
Gain on sale of discontinued operations, net of tax	—	—	—	—	(183,747)
Other(a)	8,667	(171)	4,281	2,723	6,422
Adjusted EBITDA(b)	$ 214,876	$ 214,089	$ 214,028	$ 186,880	$ 158,682

(a) Includes financial derivatives marked-to-market; income taxes; transaction costs associated with successful transactions; non-controlling interest; certain severance and exit expenses and accrued expense of a legal judgment under appeal (as allowed for adjustment under our credit facility).

(b) Adjusted EBITDA for the year ended December 31, 2009 is from continuing operations.

We define gross operating margin as revenues minus cost of purchased gas, NGLs and crude oil. We present gross operating margin by segment in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations." We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because our business is generally to purchase and resell natural gas and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil for a fee. Operating expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. We do not deduct operating expenses from total revenue in calculating gross operating margin because these expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of gross operating margin to operating income (loss):

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Total gross operating margin	$ 396,252	$ 393,758	$ 375,165	$ 338,300	$ 311,222
Add (deduct):					
Operating expenses	(150,346)	(130,882)	(111,778)	(105,060)	(110,394)
General and administrative expenses	(68,061)	(61,308)	(52,801)	(48,414)	(59,854)
Gain (loss) on sale of property	1,055	342	(264)	13,881	666
Gain (loss) on derivatives	(2,304)	(1,006)	(7,776)	(9,100)	2,994
Depreciation, amortization and impairments	(212,602)	(162,226)	(125,284)	(112,862)	(121,982)
Operating income (loss)	$ (36,006)	$ 38,678	$ 77,262	$ 76,745	$ 22,652

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

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the financial statements included in this report.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, transmission, processing, and fractionation and marketing to producers of natural gas, natural gas liquids (NGLs), crude oil and condensate. We also provide crude oil, condensate and brine services to producers. Our midstream energy asset network includes approximately 3,600 miles of pipelines, nine natural gas processing plants, four fractionators, 3.1 million barrels of NGL cavern storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. We manage and report our activities primarily according to geography. We have five reportable segments: (1) South Louisiana processing, crude and NGL, or PNGL, which includes our processing and NGL assets in South Louisiana; (2) Louisiana, or LIG, which includes our pipelines and processing plants located in Louisiana; (3) North Texas, or NTX, which includes our activities in the Barnett Shale and the Permian Basin; (4) Ohio River Valley, or ORV, which includes our activities in the Utica and Marcellus Shales; and (5) Corporate Segment, or Corporate, which includes our equity investment in Howard Energy Partners, or HEP, in the Eagle Ford Shale and our general partnership property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas, NGLs, crude oil and condensate for a margin or to gather, process, transport or market natural gas, NGLs, crude oil and condensate for a fee. In addition, we earn a volume based fee for brine disposal services. We define gross operating margin as operating revenue minus cost of purchased gas, NGLs, condensate and crude oil. Gross operating margin is a non-generally accepted accounting principle, or non-GAAP, financial measure and is explained in greater detail under "Non-GAAP Financial Measures" under "Item 6. Selected Financial Data."

Our gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, the volumes of NGLs handled at our fractionation facilities, the volumes of crude oil handled at our crude terminals, the volumes of crude oil gathered, transported, purchased and sold and the volume of brine disposed. We generate revenues from seven primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing the recovered NGLs;
- providing compression services;
- purchasing and reselling crude and condensate;
- providing crude oil transportation and terminal services; and
- providing brine disposal services.

We generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas at the market index. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, on occasion we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as our margin. Changes in the basis spread can increase or decrease our margins.

One contract (the "Delivery Contract") has a term to 2019 that obligates us to supply approximately 150,000 MMBtu/d of gas. At the time that we entered into the Delivery Contract in 2008, we had dedicated supply sources in the Barnett Shale that exceeded the delivery obligations under the Delivery Contract. Our agreements with these suppliers generally provided that the purchase price for the gas was equal to a portion of our sales price for such gas less certain fees and costs. Accordingly, we were initially able to generate a positive margin under the Delivery Contract. However, since entering into the Delivery Contract, there has been both (1) a reduction in the gas available under our supply contracts and (2) the discovery of other shale reserves, most notably the Haynesville and the Marcellus Shales, which has increased the supplies available to east coast markets and reduced the basis spread between north Texas-area production and the market indices used in the Delivery Contract. Due to these factors, we have had to purchase a portion of the gas necessary to fulfill our obligations under the Delivery Contract at market prices, resulting in negative margins under the Delivery Contract.

We have recorded a loss of approximately $18.7 million during the year ended December 31, 2013 on the Delivery Contract. We currently expect that we will record a loss of approximately $20.0 million to $24.0 million during the year ending December 31, 2014. This estimate is based on forward prices, basis spreads and other market assumptions as of December 31, 2013. These assumptions are subject to change if market conditions change during 2014 and actual results under the Delivery Contract in 2014 could be substantially different from our current estimates, which may result in a greater loss than currently estimated.

We generally gather or transport crude oil owned by others by rail, truck, pipeline and barge facilities for a fee, or we buy crude oil from a producer at a fixed discount to a market index, then transport and resell the crude oil at the market index. We execute all purchases and sales substantially concurrently, thereby establishing the basis for the margin we will receive for each crude oil transaction. Additionally, we provide crude oil, condensate and brine services on a volume basis.

We also realize gross operating margins from our processing services primarily through three different contract arrangements: processing margins (margin), percentage of liquids (POL) or fixed-fee based. Under margin contract arrangements our gross operating margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Under fixed-fee based contracts our gross operating margins are driven by throughput volume. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision, property insurance, property taxes, repair and maintenance expenses, contract services and utilities. These costs are normally fairly stable across broad volume ranges and therefore do not normally decrease or increase significantly in the short term with decreases or increases in the volume of gas, liquids or crude oil moved through or by the asset.

Our general and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, fees, services and other transaction costs related to acquisitions, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Our Business Strategy

Our business strategy consists of two overarching objectives, which are to maximize earnings and growth of our existing businesses and enhance the scale and diversification of our assets.

As part of enhancing our scale and diversification, we have concentrated on expanding our NGL business, growing a crude oil and condensate business and developing our gas processing and transportation business in rich gas areas. We believe increasing our scale and diversification will strengthen us as a company because we believe it will lead to less reliance on any single geographic area, provide us with a better balance between business driven by crude oil and natural gas, offer us greater opportunities from a broader asset base and provide us with more sustainable fee-based cash flows.

Our strategies include the following:

- *Maximize earnings and growth of our existing businesses.* We intend to leverage our franchise position, infrastructure and customer relationships in our existing areas of operation by expanding our existing systems to meet new or increased demand for our gathering, transmission, processing and marketing services.

- *Enhance the scale and diversification of our assets.* We look to grow and diversify our business through acquiring and/or building assets in new areas that will serve as a platform for future growth with a focus on emerging shale plays and other areas with NGL, crude oil and condensate exposure.

Devon Energy Transaction

On October 21, 2013, the Partnership and the Operating Partnership entered into a Contribution Agreement (the "Contribution Agreement") with Devon Energy Corporation ("Devon") and certain of its wholly-owned subsidiaries pursuant to which two of Devon's subsidiaries would contribute to the Operating Partnership 50% of the outstanding equity interests in EnLink Midstream Holdings, LP (formerly known as Devon Midstream Holdings, L.P.), a wholly-owned subsidiary of Devon referred to herein as "Midstream Holdings," and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC (formerly known as Devon Midstream Holdings GP, L.L.C.), the general partner of Midstream Holdings ("Midstream Holdings GP" and, together with Midstream Holdings and their subsidiaries, the "Midstream Group Entities"), in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership (collectively, the "Contribution") with a value of approximately $2.4 billion based on the volume weighted average closing prices of our common units for the 20 trading days prior to the announcement of the transaction. Upon completion of the Contribution, Devon and its affiliates will own approximately 53% of the limited partner interests in the Partnership, with approximately 39% of the outstanding limited partner interests held by the Partnership's public unitholders and approximately 7% of the outstanding limited partner interests (and the approximate 1% general partner interest) held indirectly by EnLink Midstream (as defined below).

The Midstream Group Entities own Devon's midstream assets in the Barnett Shale in North Texas, the Cana and Arkoma Woodford Shales in Oklahoma and Devon's interest in Gulf Coast Fractionators in Mont Belvieu, Texas. These assets consist of natural gas gathering and transportation systems, natural gas processing facilities and NGL fractionation facilities located in Texas and Oklahoma. Midstream Holdings' primary assets consist of three processing facilities with 1.3 Bcf/d of natural gas processing capacity, approximately 3,685 miles of pipelines with aggregate capacity of 2.9 Bcf/d and fractionation facilities with up to 160 MBbls/d of aggregate NGL fractionation capacity.

In connection with the Contribution Agreement, CEI entered into an Agreement and Plan of Merger (the "Merger Agreement") with Devon and certain of its wholly-owned subsidiaries, EnLink Midstream, LLC (formerly known as New Public Rangers, L.L.C.), a holding company newly formed by Devon ("EnLink Midstream"), Rangers Merger Sub, Inc., a wholly-owned subsidiary of EnLink Midstream ("Rangers Merger Sub"), and Boomer Merger Sub, Inc., a wholly-owned subsidiary of EnLink Midstream ("Boomer Merger Sub"), pursuant to which Rangers Merger Sub will merge with and into CEI, and Boomer Merger Sub will merge with and into Acacia Natural Gas Corp I, Inc., a wholly-owned subsidiary of Devon ("New Acacia") (collectively, the "Mergers"), with CEI and New Acacia surviving as wholly-owned subsidiaries of EnLink Midstream. New Acacia owns the remaining 50% limited partner interest in Midstream Holdings. Devon will own the managing member of EnLink Midstream, and EnLink Midstream will indirectly own 100% of our general partner.

The closing of the Contribution is subject to the satisfaction of a number of conditions, including, but not limited to, the closing of the Mergers. The Merger is subject to customary closing conditions, including the approval of the proposal to adopt the merger agreement by the holders of at least 67% of the issued and outstanding shares of CEI's common stock entitled to vote as of the record date for the special meeting. The special meeting is scheduled to take place on March 7, 2014. The Contribution Agreement also contains customary termination provisions and will automatically terminate upon any termination of the Merger Agreement.

Recent Developments

Cajun-Sibon Phases I and II. In Louisiana, we are transforming our business that historically has been focused on processing offshore natural gas to a business that is focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market historically has relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II will work to bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region.

We began this transformation by restarting our Eunice fractionator during 2011 at a rate of 15,000 Bbls/d of NGLs. We expanded the Eunice fractionator to a rate of 55,000 Bbls/d with Cajun-Sibon Phase I. Phase I of our pipeline extension project was completed in November 2013 and connects Mont Belvieu supply lines in east Texas to Eunice, providing a direct link to our fractionators in south Louisiana markets. The Phase I Eunice fractionator expansion, which also was completed in early November 2013, has increased our interconnected fractionation capacity in Louisiana to approximately 97,000 Bbls/d of raw-make NGLs.

The Phase I expansion added 130-miles of 12-inch diameter pipeline to our existing 440-mile Cajun-Sibon NGL pipeline system, connecting Mont Belvieu to our Eunice fractionator. The pipeline currently has a capacity of 70,000 Bbls/d for raw make NGLs. The Phase I NGL pipeline extension originates from interconnects with major Mont Belvieu supply pipelines and provides connections for NGLs from the Permian Basin, Barnett Shale, Eagle Ford and other areas to our NGL fractionation facilities and key NGL markets in south Louisiana. Phase I is anchored by a five year ethane sales agreement with Williams

Olefins, a subsidiary of the Williams Companies, and a five year natural gasoline sales agreement with another company. We have entered into contracts of various lengths for all other purity products.

We have commenced construction of Cajun-Sibon Phase II which will further enhance our Louisiana NGL business with significant additions to the Cajun-Sibon Phase I infrastructure including further fractionation expansion. Phase II will include the addition of four pumping stations, totaling 13,400 horsepower, that will facilitate increasing NGL supply capacity from Phase I's 70,000 Bbls/d to 120,000 Bbls/d; the construction of a new 100,000 Bbls/d fractionator at the Plaquemine gas processing plant site; the conversion of our Riverside fractionator to a butane-and-heavier facility; and the construction of 57 miles of NGL pipeline that will originate at the Eunice fractionator and connect to the new Plaquemine fractionator, which will provide optionality to move purity products around the Louisiana-liquids market. We will also construct a 32-mile, 16-inch diameter extension of LIG's Bayou Jack lateral, which will provide gas services to customers in the Mississippi River corridor, replacing the conversion of supply lines that we currently use for liquid service. We expect Phase II will be in service during the second half of 2014.

Phase II is anchored by 10-year sales agreements with Dow Hydrocarbons and Resources, or Dow, to deliver up to 40,000 Bbls/d of ethane and 25,000 Bbls/d of propane produced at our new Plaquemine fractionator into Dow's Louisiana pipeline system. We will also deliver 70,000 MMBtu/d of natural gas to Dow's Plaquemine facility.

We believe the Cajun-Sibon project not only represents a tremendous growth step by leveraging our Louisiana assets but that it also creates a significant platform for continued growth of our NGL business. We believe this project, along with our existing assets, will provide a number of additional opportunities to grow this business, including expanding market optionality and connectivity, upgrading products, expanding rail imports, exporting NGLs and expanding fractionation and product storage capacity.

Bearkat Natural Gas Gathering and Processing System. In the fourth quarter of 2013, we commenced construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin. The initial construction included treating, processing and gas takeaway solutions for regional producers. The project, which will be fully owned by us, is supported by a 10-year, fee-based contract.

The new-build processing complex, called Bearkat, will be strategically located near our existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant will have an initial capacity of 60 MMcf/d, increasing our total operated processing capacity in the Permian to approximately 115 MMcf/d. We will also construct a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan Counties. The entire project is scheduled to be completed in the second half of 2014.

Permian Pipeline Extension Project. In February 2014, the Partnership entered into an agreement to construct a new 35-mile, 12-inch diameter high-pressure pipeline that will provide critical gathering capacity for the aforementioned Bearkat natural gas processing complex. The pipeline will have a capacity of approximately 100 MMcf/d and will provide gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. Right-of-way acquisition is underway, and the pipeline is expected to be operational in the second half of 2014.

Riverside Crude Facility Expansion. In June 2013, we completed the Phase II expansion of our Riverside facility located on the Mississippi River in southern Louisiana. The Riverside facility’s capacity to transload crude oil and condensate from railcars to our barge facility increased to approximately 15,000 Bbls/d of crude oil and condensate. Phase II additions to the Riverside facility include a 100,000 barrel above-ground crude oil and condensate storage tank, a rail spur with a 26-spot crude railcar unloading rack and a crude oil and condensate offloading facility with pumps and metering as well as a truck unloading bay. As part of the Phase II expansion, the Riverside facility was modified so that sour crude can be unloaded in addition to sweet crude.

Issuance of Common Units. In January 2013, the Partnership issued 8,625,000 common units representing limited partner interests in the Partnership at a public offering price of $15.15 per common unit for net proceeds of $125.5 million. Concurrently with the public offering in a privately negotiated transaction, the Partnership issued 2,700,000 common units representing limited partner interests in the Partnership at an offering price of $14.55 per unit for net proceeds of $39.3 million. In June 2013, the Partnership issued 8,280,000 common units representing limited partner interests in the Partnership (including 1,080,000 common units issued pursuant to the exercise of the underwriters' option to purchase additional common units) at a public offering price of $20.33 per common unit for net proceeds of $162.0 million. The net proceeds from the common unit offerings were used for capital expenditures for capital projects, including the Cajun-Sibon natural gas liquids pipeline expansion, to repay bank borrowings and for general partnership purposes.

In March 2013, we entered into an Equity Distribution Agreement (the “EDA”) with BMO Capital Markets Corp. (“BMOCM”). Pursuant to the terms of the EDA, we could from time to time through BMOCM, as our sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Sales of such common units could be made by means of ordinary brokers' transactions through the facilities of the NASDAQ Global Select Market LLC at market prices, in block transactions or as otherwise agreed by BMOCM and us.

In May 2013, we entered into an Equity Distribution Agreement ("Replacement EDA") with BMOCM. This Replacement EDA replaced the previous EDA. Pursuant to the terms of the Replacement EDA, we could from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Sales of such common units could be made by means of ordinary brokers' transactions through the facilities of the NASDAQ Global Select Market LLC at market prices, in block transactions or as otherwise agreed by BMOCM and us.

Through December 31, 2013, we sold an aggregate of 1,181,628 common units and 3,348,213 common units under the EDA and Replacement EDA, respectively, generating proceeds of approximately $20.9 million and $72.3 million (net of approximately $0.3 million and $0.9 million of commissions to BMOCM), respectively. We used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness. We exhausted our capacity under the Replacement EDA on January 3, 2014.

Other Developments. HEP is continuing to expand its midstream assets in the Eagle Ford Shale in south Texas. We contributed an additional $30.6 million to HEP during the year ended December 31, 2013 to fund our 30.6% share of HEP's expansion costs. In December 2013, Alinda Capital Partners acquired a 59% capital interest in HEP from Quanta Capital Solutions and GE Energy Financial Services. We also received cash distributions totaling $17.5 million from HEP during the year ended December 31, 2013.

Commodity Price Risk

We are subject to significant risks due to fluctuation in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. Processing margin and percent of liquids contracts are two types of contracts under which the we process gas and are exposed to commodity price risk. For the year ended December 31, 2013, approximately 9.0% of our processed gas arrangements, based on gross operating margin, were processed under POL contracts. A portion of the volume of inlet gas at our south Louisiana and north Texas processing plants is settled under POL agreements. Under these contracts we receive a fee in the form of a percentage of the liquids recovered and the producer bears all the costs of the natural gas volumes lost ("shrink"). Accordingly, our revenues under these contracts are directly impacted by the market price of NGLs.

We also realize processing gross operating margin under margin contracts and spot purchases. For the year ended December 31, 2013, approximately 5.6% of our processed gas arrangements, based on gross operating margin, was processed under margin contracts and spot purchases. We have a number of margin contracts on our Plaquemine, Gibson, Eunice, Blue Water and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas shrink and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR.

We are also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of natural gas, NGLs and crude oil connected to or near our assets and on our margins for transportation between certain market centers. Low prices for these products could reduce the demand for our services and volumes on our systems.

In the past, the prices of oil, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2013 ranged from a high of $110.53 per Bbl in September 2013 to a low of $86.68 per Bbl in April 2013. Weighted average NGL prices in 2013 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a high of $1.09 per gallon in September 2013 to a low of $0.84 per gallon in June 2013. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2013 ranged from a high of $4.52 per MMBtu in December 2013 to a low of $3.08 per MMBtu in January 2013.

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas we gather and process. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. For a discussion of our risk management activities, please read "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Results of Operations

Set forth in the table below is certain financial and operating data for the periods indicated, which includes our 2012 acquisition of the ORV assets from date of acquisition and excludes financial and operating data deemed discontinued operations. We manage our operations by focusing on gross operating margin, which we define as revenues minus cost of purchased gas, NGLs and crude oil as reflected in the table below.

	Years Ended December 31,		
	2013	2012	2011
	(Dollars in millions)		
LIG Segment			
Revenues	$ 580.3	$ 786.9	$ 939.3
Purchased gas and NGLs	(495.8)	(678.2)	(809.5)
Total gross operating margin	$ 84.5	$ 108.7	$ 129.8
NTX Segment			
Revenues	$ 394.0	$ 365.5	$ 432.6
Purchased gas and NGLs	(229.7)	(180.1)	(262.7)
Total gross operating margin	$ 164.3	$ 185.4	$ 169.9
PNGL Segment			
Revenues	$ 872.4	$ 998.2	$ 910.9
Purchased gas and NGLs	(778.0)	(924.2)	(835.4)
Total gross operating margin	$ 94.4	$ 74.0	$ 75.5
ORV Segment			
Revenues	$ 280.8	$ 108.0	$ —
Purchased crude oil and condensate	(227.7)	(82.3)	—
Total gross operating margin	$ 53.1	$ 25.7	$ —
Corporate			
Revenues	$ (184.2)	$ (467.3)	$ (268.9)
Purchased gas, NGLs, condensate and crude oil	184.2	467.3	268.9
Total gross operating margin	$ —	$ —	$ —
Total			
Revenues	$ 1,943.3	$ 1,791.3	$ 2,013.9
Purchased gas, NGLs, condensate and crude oil	(1,547.0)	(1,397.5)	(1,638.7)
Total gross operating margin	$ 396.3	$ 393.8	$ 375.2
Midstream Volumes:			
LIG			
Gathering and Transportation (MMBtu/d)	473,000	783,000	912,000
Processing (MMBtu/d)	255,000	248,000	247,000
NTX			
Gathering and Transportation (MMBtu/d)	1,042,000	1,160,000	1,125,000
Processing (MMBtu/d)	382,000	364,000	249,000
PNGL			
Processing (MMBtu/d)	399,000	738,000	829,000
NGL Fractionation (Gals/d) (1)	1,473,000	1,359,000	1,109,000
ORV*			
Crude Oil Handling (Bbls/d)(2)	12,000	11,800	—
Brine Disposal (Bbls/d)(2)	7,000	7,800	—

* Crude oil handling from PNGL is included in ORV reported volumes.

(1) Includes Cajun-Sibon pipeline volumes, which are transported to our southern Louisiana assets for fractionation.

(2) Crude oil handling and brine disposal volume for ORV for the year ended December 31, 2012 include a daily average for July 2012 through December 31, 2012, the six-month period these assets were operated by us.

Year ended December 31, 2013 Compared to Year ended December 31, 2012

Gross Operating Margin. Gross operating margin was $396.3 million for the year ended December 31, 2013 compared to $393.8 million for the year ended December 31, 2012, an increase of $2.5 million. The following provides additional details regarding this change in gross operating margin:

- The ORV segment gross operating margin increased $27.4 million for the year ended December 31, 2013 compared to the year ended December 31, 2012, which only included operations for six months in 2012 from the date of acquisition. Gross operating margin increased $27.7 million related to our operation of the ORV assets during the first half on 2013 as compared to 2012. Gross operating margin for the second half of 2013 compared to 2012 remained relatively unchanged.

- The PNGL segment had a gross operating margin increase of $20.4 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Our NGL fractionation and marketing activities contributed $24.1 million of gross operating margin increase due to improved margins from seasonal pricing spreads, and increased margins from truck and rail activity and increased NGL volumes from the November 2013 start-up of the Cajun-Sibon pipeline and the Eunice fractionator. The PNGL segment also includes our crude oil terminal activity in south Louisiana, which contributed $3.6 million of the gross operating margin increase. These increases were offset by a combined gross operating margin decrease of $7.3 million from our south Louisiana processing plants due to a less favorable processing environment, which caused a significant decline in volumes processed through the plants as well as declines in margins earned on those volumes. The Pelican processing plant was the only PNGL plant in service throughout 2013 and is the only plant currently in service.

- The NTX segment had a decrease in gross operating margin of $21.1 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Gross operating margin increased by $3.2 million from our gas processing facilities primarily due to increased throughput on our Permian Basin system. This increase was offset by a decline in our gross operating margin of $24.3 million from our gathering and transmission assets due to a decline in our throughput volumes together with reduced gathering rates under certain contracts, including a contract with a major producer in north Texas.

- The LIG segment had a decrease in gross operating margin of $24.2 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Gross operating margin decreased by $5.6 million from our Gibson and Plaquemine plants and decreased by $3.8 million from gas processed for our account by a third-party processor, in each case, due to a weaker processing environment during 2013 as compared to 2012. Gross operating margins decreased by $14.8 million on the gathering and transmission assets due to sales volumes lost related to the Bayou Corne sinkhole, loss of opportunity sales volumes due to lower processing margins and lower blending and treating volumes for the year ended December 31, 2013 as compared to the year ended December 31, 2012. Although our north LIG system in the Haynesville Shale had volume declines, most of these volume declines were associated with gas transported under firm transportation agreements so we only realized a slight decrease in our transportation fee income on our north LIG system.

Operating Expenses. Operating expenses were $150.3 million for the year ended December 31, 2013 compared to $130.9 million for the year ended December 31, 2012, an increase of $19.5 million, or 14.9%. This increase in operating expenses is primarily driven by an increase of $20.0 million related to the direct operating costs of the ORV assets for twelve months during 2013 as compared to only six months during 2012, which was offset by a decrease of $0.7 million at the other segments. The primary contributors to the total increase are as follows:

- our labor and benefits expense increased by $11.1 million related to an increase in employee headcount following the acquisition of our ORV assets and project expansion in our PNGL segment;

- our rents, leases and vehicle expenses increased $4.3 million primarily related to the acquisition and subsequent operations of our ORV assets; and

- our regulatory and tax expenses increased by $3.2 million due to increased ad valorem tax expenses on our ORV and NTX assets.

General and Administrative Expenses. General and administrative expenses were $68.1 million for the year ended December 31, 2013 compared to $61.3 million for the year ended December 31, 2012, an increase of $6.8 million, or 11.1%. The increase is primarily a result of the following:

- our labor and benefits expense increased by $0.8 million primarily due to an increase in headcount primarily related to the acquisition of our ORV assets and activity related to project expansion in our PNGL segment, partially offset by a decrease in overall bonus expense;
- our stock based compensation expense increased by $4.4 million due to an increase in headcount, including $2.0 million attributable to certain bonuses paid in March 2013 in the form of stock and unit awards that immediately vested;
- our fees and services expense increased by $0.4 million primarily due to $3.2 million of transaction costs in 2013 related to the proposed business combination with Devon as compared to $2.8 million of transaction costs in 2012;
- our rents, leases and vehicle expenses increased by $0.5 million primarily due to an increase in office rent; and
- our communication related costs increased by $0.5 million primarily due to network upgrades for our ORV assets.

Loss on Derivatives. Loss on derivatives was $2.3 million for the year ended December 31, 2013 compared to a loss of $1.0 million for the year ended December 31, 2012. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Years Ended December 31,			
	2013		2012	
(Gain) Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ 1.0	$ 1.9	$ 5.2	$ 4.6
Processing margin hedges	(0.2)	(1.7)	(3.1)	0.5
Liquids Swaps-non designated	1.1	—	(1.0)	—
Storage/Inventory Swaps	0.4	0.4	(0.1)	(0.6)
Net loss on derivatives	$ 2.3	$ 0.6	$ 1.0	$ 4.5

Depreciation and Amortization. Depreciation and amortization expenses were $140.0 million for the year ended December 31, 2013 compared to $162.2 million for the year ended December 31, 2012, a decrease of $22.2 million, or 13.7%. This decrease includes $27.8 million related to accelerated depreciation and amortization of the Sabine Pass Plant included in 2012, $4.9 million of decreased intangible amortization related to the Eunice processing plant impairment discussed below, and $5.4 million of decreased intangible amortization related to the revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in north Texas. These decreases were partially offset by $16.0 million of additional depreciation due to net asset additions, including $6.5 million related to the July 2012 acquisition of the ORV assets for the twelve months in 2013 as compared to six months in 2012, and $9.4 million related primarily to the Cajun Sibon pipeline, which came into service in November 2013.

Impairment. Impairment expense was $72.6 million for the year ended December 31, 2013. No impairment was recorded in 2012. The impairment relates to the termination of customer's contracts associated with Eunice processing plant which was shut down in August 2013 due to poor processing economics.

Interest Expense. Interest expense was $76.2 million for the year ended December 31, 2013 compared to $86.5 million for the year ended December 31, 2012, a decrease of $10.3 million, or 11.9%. The increases and decreases in our interest bearing obligations are depicted below. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2013	2012
Senior notes	$ 82.0	$ 75.1
Bank credit facility	6.2	6.5
Capitalized interest (1)	(22.3)	(4.0)
Amortization of debt issue costs and notes discount	8.0	7.3
Other	2.3	1.6
Total	$ 76.2	$ 86.5

(1) The increase in capitalized interest is primarily related to project expansions in our PNGL segment.

Equity in income of limited liability company. Equity in income of limited liability company was less than $0.1 million for the year ended December 31, 2013 compared to $3.3 million for the year ended December 31, 2012. The decrease of $3.2 million of equity in earnings relates to our investment in HEP.

Other Income. Other income was $1.4 million for the year ended December 31, 2013 compared to $5.1 million for the year ended December 31, 2012. Other income in 2013 primarily relates to a settlement of certain legal liabilities for less than the accrued liability resulting in a $1.0 million gain. Other income in 2012 includes a $3.0 million net gain related to the assignment to a third party of our rights, title and interest in a contract for the construction of a processing plant. In addition, we settled certain liabilities associated with sold assets for less than the accrued liabilities resulting in a $1.3 million gain during 2012.

Income Tax Expense. Income tax expense was $2.3 million for the year ended December 31, 2013 compared to $0.7 million for the year ended December 31, 2012, an increase of $1.5 million. The increase is due to income taxes attributable to the wholly-owned corporate entity that was formed to acquire the ORV assets in July 2012 and is subject to income taxes.

Year ended December 31, 2012 Compared to Year ended December 31, 2011

Gross Operating Margin. Gross operating margin was $393.8 million for the year ended December 31, 2012 compared to $375.2 million for the year ended December 31, 2011, an increase of $18.6 million, or 5.0%. The overall increase was due to the July 2012 acquisition of the ORV assets, increased throughput on our NTX and Permian Basin systems, an increase in NGL fractionation and marketing activity and an increase from our south Louisiana crude oil terminal activity. The following provides additional details regarding this change in gross operating margin:

- The ORV segment contributed a total of $25.7 million to our gross operating margin growth for the year ended December 31, 2012. Gross operating margins from crude oil and condensate handling and brine disposal and handling were $17.2 million and $8.5 million, respectively.
- The LIG segment had a gross operating margin decline of $21.1 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. The weaker processing environment during 2012 as compared to 2011 contributed to a decrease in gross operating margin for the processing activities during the year ended December 31, 2012. Due to this weaker environment, gross operating margin decreased by $7.7 million at the Plaquemine and Gibson plants and by $9.0 million from gas processed for our account by a third party processor. Gross operating margins decreased by $4.4 million on the gathering and transmission assets due to decreased throughput volumes which includes the impact of Bayou Corne sinkhole discussed more fully under "Liquidity and Capital Resources - Changes in Operations During 2013 and 2012."
- The NTX segment had a gross operating margin increase of $15.5 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. An increase in throughput volume on the gathering and transmission assets from two north Texas expansion projects contributed $5.8 million to the gross operating margin improvement. The north Texas processing plants also had a gross operating margin increase of $4.3 million for the comparable periods primarily due to increased supply due to our expansion projects. In addition, the gas processing facilities located in the Permian Basin, which commenced operations in 2012, contributed $9.6 million to gross operating margin. These increases were partially offset by an increase in losses of $4.2 million on the Delivery Contract discussed more fully under "Overview."

- The PNGL segment had a gross operating margin decrease of $1.5 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. Our NGL fractionation and marketing activities contributed a gross operating margin improvement of $11.6 million as a result of the growth and expansion of our NGL fractionation and marketing activities. We increased our NGL fractionation and marketing activities through the restart of the Eunice fractionator in June 2011 and by increasing our truck and rail activity at our Riverside fractionator. These increases were offset by a combined gross operating margin decrease of $18.3 million from our south Louisiana processing plants due to a less favorable processing environment during 2012 as compared to 2011. Our crude oil terminal activity in south Louisiana also contributed a gross operating margin increase of $5.2 million during the year ended December 31, 2012.

Operating Expenses. Operating expenses were $130.9 million for the year ended December 31, 2012 compared to $111.8 million for the year ended December 31, 2011, an increase of $19.1 million, or 17.1%. The increase in operating expenses includes a total increase of $11.9 million related to the direct operating costs of the ORV assets that we purchased in July 2012. The primary contributors to the total increase are as follows:

- our labor and benefits expense increased by $9.5 million related to the acquisition of our ORV assets and an increase in employee headcount for activity related to the Permian Basin expansions in the North Texas segment and for growth projects in the PNGL segment;
- our materials, supplies and contractor service expenses increased by $5.8 million related to the acquisition of our ORV assets, project expansions in the North Texas and PNGL segments and compressor overhauls;
- our rents, leases, vehicle and utility expenses increased $1.8 million due to increases from the acquisition of our ORV assets and project expansions in the North Texas and PNGL segments, which were partially offset by reductions in compressor rental and utilities expenses in the LIG segment;
- our training, audit and consulting expenses related to regulatory activity increased by $1.2 million;
- our ad valorem tax expense increased by $2.0 million due to project expansions; and
- our other expenses decreased by $2.0 million due to the 2011 accrual of a legal judgment under appeal.

General and Administrative Expenses. General and administrative expenses were $61.3 million for the year ended December 31, 2012 compared to $52.8 million for the year ended December 31, 2011, an increase of $8.5 million, or 16.1%. The increase is primarily a result of the following:

- our fees and services expense increased by $6.3 million primarily due to $2.8 million of acquisition cost for our ORV assets and $2.2 million for evaluation expenses related to potential acquisitions;
- our stock based compensation expense increased by $1.8 million;
- our labor and benefits expense decreased by $0.2 million primarily related to a decrease in bonuses substantially offset by an increase in labor and benefit expenses due to an increase in employee headcount; and
- our traveling and training expense increased by $0.5 million primarily due to acquisition activities.

Loss on Derivatives. Loss on derivatives was $1.0 million for the year ended December 31, 2012 compared to a loss of $7.8 million for the year ended December 31, 2011. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Years Ended December 31,			
	2012		2011	
(Gain) Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ 5.2	$ 4.6	$ 1.4	$ 1.3
Processing margin hedges	(3.1)	0.5	6.6	5.7
Liquids Swaps-non designated	(1.0)	—	—	—
Storage/Inventory Swaps	(0.1)	(0.6)	(0.3)	—
Other	—	—	0.1	—
Net loss on derivatives	$ 1.0	$ 4.5	$ 7.8	$ 7.0

Depreciation and Amortization. Depreciation and amortization expenses were $162.2 million for the year ended December 31, 2012 compared to $125.3 million for the year ended December 31, 2011, an increase of $36.9 million, or 29.5%. The increase includes $24.9 million due to accelerated depreciation related to the Sabine Pass plant, $4.9 million related to depreciation on the ORV assets and $2.8 million related to depreciation on additions in the Permian area. In addition, amortization increased $3.1 million due to intangible amortization related to a downward revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in north Texas and a $1.2 million impact due to depreciation on other net asset additions.

Interest Expense. Interest expense was $86.5 million for the year ended December 31, 2012 compared to $79.2 million for the year ended December 31, 2011, an increase of $7.3 million, or 9.2%. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2012	2011
Senior notes (secured and unsecured)	$ 75.1	$ 64.3
Bank credit facility	6.5	5.5
Capitalized interest	(4.0)	(0.9)
Amortization of debt issue costs an notes discount	7.3	8.3
Other	1.6	2.0
Total	$ 86.5	$ 79.2

Equity in income of limited liability company. Equity in income of limited liability company was $3.3 million for the year ended December 31, 2012 compared to no equity in income for the year ended December 31, 2011. Equity in income of limited liability company relates to our investment in HEP.

Other Income. Other income was $5.1 million for the year ended December 31, 2012 compared to $0.7 million for the year ended December 31, 2011. Other income in 2012 includes a $3.0 million net gain related to the assignment to a third party of our rights, title and interest in a contract for the construction of a processing plant. In addition, we settled certain liabilities associated with sold assets for less than the accrued liabilities resulting in a $1.3 million gain during 2012.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. Our critical accounting policies are discussed below. See Note 2 of the Notes to Consolidated Financial Statements for further details on our accounting policies.

Revenue Recognition and Commodity Risk Management. We recognize revenue for sales or services at the time the natural gas, NGLs or crude oil is delivered or at the time the service is performed. We generally accrue one month of sales and the related gas, NGL or crude oil purchases and reverse these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

We utilize extensive estimation procedures to determine the sales and cost of gas, NGL or crude oil purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. We use actual measurement data, if it is available, and will use such data as producer/shipper nominations, prior month average daily flows, estimated flow for new production and estimated end-user requirements (all adjusted for the estimated impact of weather patterns) when actual measurement data is not available. Throughout the month or two following production, actual measured sales and transportation volumes are received and invoiced and used in a process referred to as "actualization." Through the actualization process, any estimation differences recorded through the accrual are reflected in the subsequent month's accounting cycle when the accrual is reversed and actual amounts are recorded. Actual volumes purchased, processed or sold may differ from the estimates due to a variety of factors including, but not limited to: actual wellhead production or customer requirements being higher or lower than the amount nominated at the beginning of the month; liquids recoveries being higher or lower than estimated because gas processed through the plants was richer or leaner than estimated; the estimated impact of weather patterns being different from the actual impact on sales and purchases; and pipeline maintenance or allocation causing actual deliveries of gas to be different than estimated. We believe that our accrual process for sales and purchases provides a reasonable estimate of such sales and purchases.

We engage in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas, NGLs, crude oil and condensate. We also manage our price risk related to future physical purchase or sale commitments by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas and NGL prices.

We use derivatives to hedge against changes in cash flows related to product prices, as opposed to their use for trading purposes. FASB ASC 815 requires that all derivatives and hedging instruments are recognized as assets or liabilities at fair value. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

We conduct "off-system" gas marketing operations as a service to producers on systems that we do not own. We refer to these activities as part of energy trading activities. In some cases, we earn an agency fee from the producer for arranging the marketing of the producer's natural gas. In other cases, we purchase the natural gas from the producer and enter into a sales contract with another party to sell the natural gas. The revenue and cost of sales for these activities are included in revenue on a net basis in the statement of operations.

We manage our price risk related to future physical purchase or sale commitments for energy trading activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance future commitments and significantly reduce risk related to the movement in natural gas prices. However, we are subject to counter-party risk for both the physical and financial contracts. Our energy trading contracts qualify as derivatives and we use mark-to-market accounting for both physical and financial contracts of the energy trading business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to energy trading activities are recognized in earnings as gain or loss on derivatives immediately.

Impairment of Long-Lived Assets. In accordance with FASB ASC 360-10-05, we evaluate the long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas and crude oil prices. Projections of gas and crude oil volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;
- the availability and prices of natural gas and crude oil supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas and crude oil exploration and production activities will not occur or be successful;
- our dependence on certain significant customers, producers and transporters of natural gas and crude oil; and
- competition from other midstream companies, including major energy producers.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

Impairment of Goodwill. Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of July 1 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. We evaluated our goodwill for impairment on July 1, 2013. Our goodwill impairment analysis performed on that date did not result in an impairment as the fair value of the ORV reporting unit substantially exceeded our carrying value, and subsequent to that date, no event has occurred indicating that the implied fair value of the reporting unit is less than the carrying value of our net assets.

Depreciation Expense and Cost Capitalization. Our assets consist primarily of natural gas, NGL, condensate and crude oil gathering pipelines, processing plants, transmission pipelines and trucks. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed assets through the recording of depreciation expense. We capitalize the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred.

We generally compute depreciation using the straight-line method over the estimated useful life of the assets. Certain assets such as land, NGL line pack, natural gas line pack and crude oil line pack are non-depreciable. The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, we may review depreciation estimates to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values, which would impact future depreciation expense.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $95.2 million, $103.9 million and $143.6 million for the years ended December 31, 2013, 2012 and 2011, respectively. Operating cash flows and changes in working capital for 2013, 2012 and 2011 were as follows (in millions):

	Years Ended December 31,		
	2013	2012	2011
Operating cash flows before working capital	$ 120.0	$ 127.3	$ 138.9
Changes in working capital	(24.9)	(23.4)	4.7
Total	$ 95.1	$ 103.9	$ 143.6

The primary reason for the decrease in cash flows before working capital of $7.3 million from 2012 to 2013 relates to increases in operating expenses and general and administrative expenses partially offset by an increase in gross operating margin.

The change in working capital for 2013, 2012 and 2011 primarily relates to normal fluctuations in trade receivable and payable balances due to timing of collections and payments.

Cash Flows from Investing Activities. Net cash used in investing activities was $481.1 million, $490.3 million and $132.1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Our primary use of cash related to investing activities for the years ended December 31, 2013, 2012 and 2011 was acquisition costs and capital expenditures, net of accrued amounts, and an investment in limited liability company as follows (in millions):

	Years Ended December 31,		
	2013	2012	2011
Growth capital expenditures	$ 472.6	$ 221.2	$ 85.0
Acquisition and asset purchases	—	215.0	—
Maintenance capital expenditures	11.5	13.6	12.6
Investment in limited liability company	30.6	52.3	35.0
Total	$ 514.7	$ 502.1	$ 132.6

Cash flows from investing activities for the years ended December 31,2013, 2012 and 2011 also included proceeds from property sales of $19.4 million, $11.8 million and $0.5 million, respectively. Proceeds from property sales for the year ended December 31, 2013 relate to our sale of the local distribution companies acquired in connection with our July 2012 acquisition of our ORV assets, which were classified as held for disposition on the balance sheet as of December 31, 2012. Proceeds from property sales for the year ended December 31, 2012 include $11.1 million received for the assignment to a third party of the rights, title and interest in a contract for the construction of a processing plant. Also, we received cash distributions from HEP totaling $17.5 million for the year ended December 31, 2013, $14.2 million of which was classified as cash flows from investing from limited liability company in excess of earnings.

Cash Flows from Financing Activities. Net cash provided by financing activities was $385.9 million and $362.4 million for the years ended December 31, 2013 and 2012, respectively, and net cash used in financing activities was $5.0 million for the year ended 2011. Our primary financing activities consist of the following (in millions):

	Years Ended December 31,		
	2013	2012	2011
Net borrowings (repayments) under bank credit facilities	$ 84.0	$ (14.0)	$ 85.0
2022 Notes borrowings	—	250.0	—
Net payments under other debt	(3.3)	(3.1)	(10.2)
Debt refinancing costs	(2.0)	(7.2)	(4.0)
Proceeds from issuance of Partnership units(1)(2)	419.5	236.2	—

(1) Includes our general partner's proportionate contribution in the May 2012 offering and net of costs associated with our equity offerings.

(2) On September 13, 2012, the board of directors of our general partner amended the Partnership agreement to convert our general partner's obligation to make capital contributions to us to maintain its 2% interest in connection with the issuance of additional limited partner interests by us to an option of our general partner to make future capital contributions to maintain its then current general partner percentage interest.

Distributions to unitholders and our general partner represent one of our primary uses of cash in financing activities. Total cash distributions made during the years ended December 31, 2013, 2012 and 2011 were as follows (in millions):

	Years ended December 31,		
	2013 (2)	2012	2011
Common units	$ 113.3	$ 76.5	$ 60.2
Preferred units(1)	—	14.4	17.2
General partner interest (including incentive distribution rights)	7.2	5.8	3.3
Total	$ 120.5	$ 96.7	$ 80.7

(1) Excludes distributions paid through the issuance of paid-in-kind preferred units for third quarter of 2012 and for all of 2013.
(2) Excludes distribution declared for the fourth quarter of 2013, which were paid on February 12, 2014.

On January 19, 2010, we issued approximately $125.0 million (14,705,882 units) of Series A Convertible Preferred Units (the "preferred units") to an affiliate of Blackstone/GSO Capital Solutions pursuant to an exemption from registration under Section 4(2) of the Securities Act of 1933, as amended (the "Securities Act"). The preferred units were convertible into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. Holders of the preferred units were entitled to receive quarterly cash distributions with a value equal to the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders. Such distributions were paid in cash during 2010 through the second quarter of 2012.

Beginning in the third quarter of 2012 through the fourth quarter of 2013, the quarterly distributions on the preferred units were paid-in-kind resulting in the issuance of 2,389,250 additional preferred units with the last distribution paid-in-kind on February 12, 2014. All future quarterly preferred unit quarterly distributions will be paid in cash.

We had the right to force conversion of the preferred units if (i) the daily volume weighted average trading price of the common units is greater than $12.75 per unit for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion, and (ii) the average trading volume of common units exceeds a specified number of common units (the “trading volume threshold”) for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion. On February 27, 2014, the board of directors of our general partner amended our partnership agreement to reduce the trading volume threshold from 250,000 common units to 215,000, and on that same date we delivered a notice of conversion of all outstanding preferred units.

The indentures governing our senior unsecured notes provide the ability to pay distributions if a minimum fixed charged coverage ratio is met and also provide baskets to make payments if such minimum is not met.

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility. We borrow money under our $635.0 million credit facility to fund checks as they are presented. As of December 31, 2013, we had approximately $420.3 million of available borrowing capacity under this facility, although our actual borrowing capacity is limited by our financial covenants. Changes in drafts payable for 2013, 2012 and 2011 were as follows (in millions):

	Years Ended December 31,		
	2013	2012	2011
Increase (decrease) in drafts payable	$ 9.3	$ (1.9)	$ 5.9

Working Capital Deficit. We had a working capital deficit of $16.8 million as of December 31, 2013. Changes in working capital may fluctuate significantly between periods even though our trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of our revenues are collected and a large volume of our gas and crude oil purchases are paid near each month end or the first few days of the following month so receivable and payable balances at any month end may fluctuate significantly depending on the timing of these receipts and payments. In addition, although we strive to minimize our natural gas and NGLs in inventory, these working inventory balances may fluctuate significantly from period to period due to operational reasons and changes in natural gas and NGL prices. The changes in working capital during the years ended December 31, 2013 and 2011 are due to the impact of the price fluctuations discussed above.

Changes in Operations During 2013 and 2012. We have a gas gathering contract with a major producer in our North Texas assets with a primary term that expired August 31, 2012 that was modified to be on a month-to-month basis beginning September 1, 2012. Subsequently, the modified contract was extended for six months at a reduced gathering fee rate which did and will reduce our gross operating margin by approximately $1.2 million per quarter. The contract is currently rolling month to month in evergreen status (under the terms of the previously mentioned six month extension), and we are in the process of attempting to negotiate a longer term agreement.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs. The cause of the sinkhole is currently under investigation by Louisiana state and local officials. We took a section of our 36-inch-diameter natural gas pipeline located near the sinkhole out of service. Service to certain markets, primarily in the Mississippi River area, has been curtailed or interrupted, and we have worked with our customers to secure alternative natural gas supplies so that disruptions are minimized. We estimate that the overall business impact on services previously provided by the pipeline, which included gathering, processing, transportation and end-user sales, is approximately $0.25 million to $0.3 million per month while the pipeline is out of service. We are currently in the initial phase of constructing the replacement pipeline in our rerouted location and anticipate such construction will be completed during first half of 2014. The estimated cost for this pipeline replacement is $25.0 million.

We are assessing the potential for recovering our losses from responsible parties, and we are seeking recovery from our insurers. Our insurers, however, have denied our insurance claim for coverage and filed a declaratory judgment asking a court to determine that our insurance policy does not cover this damage. We have sued our insurers for breach of contract due to their refusal to pay our insurance claim for this damage. We have also sued Texas Brine, LLC, the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

Capital Requirements. Our 2014 capital budget includes approximately $450.0 million to $500.0 million of identified growth projects, including capital interest. Our primary capital projects for 2014 include the expansion of the Cajun-Sibon NGL

Pipeline Phase II and construction of our Bearkat plant facilities. During2013, we invested in several capital projects which primarily included the expansion of the Cajun-Sibon NGL Pipeline. See "Item 1. Business—Recent Growth Developments" for further details.

We expect to fund our 2014 maintenance capital expenditures of approximately $15.2 million from operating cash flows. We expect to fund the growth capital expenditures from the proceeds of borrowings under our bank credit facility discussed below and proceeds from other debt and equity sources. In 2014, it is possible that not all of the planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2013, 2012 and 2011.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as ofDecember 31, 2013 is as follows (in millions):

	Payments Due by Period						
	Total	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**
Long-term debt obligations*	$ 975.0	$ —	$ —	$ —	$ —	$ 725.0	$ 250.0
Bank credit facility	155.0	—	—	155.0	—	—	—
Interest payable on fixed long-term debt obligations	440.0	82.1	82.1	82.2	82.2	49.1	62.3
Capital lease obligations	25.2	4.6	4.6	4.6	6.9	2.9	1.6
Operating lease obligations	55.6	10.2	10.3	8.4	5.2	5.8	15.7
Purchase obligations	14.2	14.2	—	—	—	—	—
Additional benefit obligations	3.5	3.5	—	—	—	—	—
Inactive easement commitment**	10.0	—	—	—	—	—	10.0
Uncertain tax position obligations	3.8	3.8	—	—	—	—	—
Total contractual obligations	$ 1,682.3	$ 118.4	$ 97.0	$ 250.2	$ 94.3	$ 782.8	$ 339.6

* Effective as of February 2, 2014, we redeemed approximately $53.5 million in aggregate principal amount of the 2022 Notes (as defined below) pursuant to the terms of the indenture governing such notes. See "—Indebtedness—Senior Unsecured Notes."

** Amounts related to inactive easements paid as utilized with remaining balance of easements not utilized due at end of 10 years.

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.

The interest payable under our credit facility is not reflected in the above table because such amounts depend on outstanding balances and interest rates, which will vary from time to time. However, given the same borrowing amount and rates in effect at December 31, 2013 our cash obligation for interest expense on our credit facility would be approximately $5.0 million per year.

Indebtedness

As of December 31, 2013 and 2012, long-term debt consisted of the following (in millions):

	2013	2012
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2013 and December 31, 2012 was 3.2% and 4.3%, respectively	$ 155.0	$ 71.0
Senior unsecured notes (due 2018), net of discount of $7.8 million and $9.7 million, respectively, which bear interest at the rate of 8.875%	717.2	715.3
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250.0	250.0
Debt classified as long-term	$ 1,122.2	$ 1,036.3

Existing Credit Facility. We amended our existing bank credit facility in January 2013, August 2013 and January 2014. All references herein to our existing credit facility include, as applicable, such amendments. Among other things, the amendments contained the following changes:

- permitted the Partnership to make additional investments in joint ventures and subsidiaries that are not guarantors of the Partnership's obligations under the existing credit facility;
- decreased the minimum consolidated interest coverage ratio to 2.25 to 1.0 for the fiscal quarters ending March 31, 2014, June 30, 2014, September 30, 2014 and December 31, 2014, with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter;
- increased the maximum permitted consolidated leverage ratio to 5.50 to 1.0 for the fiscal quarters ending March 31, 2014, June 30, 2014 and September 30, 2014, with a maximum ratio of 5.25 to 1.0 for each fiscal quarter ending thereafter; and
- amended the definition of "change of control" so that the consummation of the Merger and the Contribution will not constitute an event of default.

As of December 31, 2013, there was $155.0 million of outstanding borrowings and $59.7 million in outstanding letters of credit under the existing credit facility leaving approximately $420.3 million available for future borrowings and letters of credit based on a borrowing capacity of$635.0 million. However, the financial covenants in the existing credit facility limit the amount of funds that we can borrow. As of December 31, 2013, based on the financial covenants in the existing credit facility, we could borrow approximately $207.1 million of additional funds.

The existing credit facility is guaranteed by substantially all of our subsidiaries and is secured by first priority liens on substantially all of our assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in substantially all of our subsidiaries.

We may prepay all loans under the existing credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The existing credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, extraordinary receipts, equity issuances and debt incurrences, but these mandatory prepayments do not require any reduction of the lenders' commitments under the existing credit facility.

Under the existing credit facility, borrowings bear interest at our option at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. We pay a per annum fee (as described below) on all letters of credit issued under the existing credit facility and a commitment fee of between 0.375% and 0.50% per annum on the unused availability under the existing credit facility. The commitment fee, letter of credit fee and the applicable margins for the interest rate vary quarterly based on our leverage ratio (as defined in the existing credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans and Letter of Credit Fees	Letter of Commitment Fees
Greater than or equal to 4.50 to 1.00	2.00%	3.00%	0.50%
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	1.75%	2.75%	0.50%
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	1.50%	2.50%	0.50%
Greater than or equal to 3.00 to 1.00 and less than 3.50 to 1.00	1.25%	2.25%	0.50%
Less than 3.00 to 1.00	1.00%	2.00%	0.375%

The existing credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The minimum consolidated interest coverage ratio (as defined in the existing credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is 2.25 to 1.0 for the fiscal quarters ending March 31, 2014, June 30, 2014, September 30, 2014 and December 31, 2014 with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter. The maximum permitted senior leverage ratio (as defined in the existing credit facility, but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non cash charges) is 2.75 to 1.00. The maximum permitted leverage ratio (as defined in the existing credit facility, but generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 5.50 to 1.0 for the fiscal quarters ending March 31, 2014, June 30, 2014 and September 30, 2014 with a maximum ratio of 5.25 to 1.0 for each fiscal quarter thereafter.

In addition, the existing credit facility contains various covenants that, among other restrictions, limit our ability to:

- grant or assume liens;
- make investments;
- incur or assume indebtedness;
- engage in mergers or acquisitions (as defined in existing credit facility);
- sell, transfer, assign or convey assets;
- repurchase our equity, make distributions and certain other restricted payments;
- change the nature of our business;
- engage in transactions with affiliates;
- enter into certain burdensome agreements;
- make certain amendments to the omnibus agreement, our or our subsidiaries' organizational documents;
- prepay the senior unsecured notes and certain other indebtedness; and
- enter into certain hedging contracts.

The existing credit facility permits us to make quarterly distributions to unitholders so long as no default exists under the existing credit facility.

Each of the following is an event of default under the existing credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation or covenant in the credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- our or any of our subsidiaries' default under other indebtedness that exceeds a threshold amount;
- judgments against us or any of our material subsidiaries, in excess of a threshold amount;
- certain ERISA events involving us or any of our material subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving us or any of our material subsidiaries; and
- a change in control (as defined in the existing credit facility).

If an event of default relating to bankruptcy or other insolvency events occur, all indebtedness under the existing credit facility will immediately become due and payable. If any other event of default exists under the existing credit facility, the lenders may accelerate the maturity of the obligations outstanding under the existing credit facility and exercise other rights and remedies. In addition, if any event of default exists under the existing credit facility, the lenders may commence foreclosure or other actions against the collateral.

If any default occurs under the existing credit facility, or if we are unable to make any of the representations and warranties in the existing credit facility, we will be unable to borrow funds or have letters of credit issued under the existing credit facility.

The Partnership expects to be in compliance with the covenants in the existing credit facility for at least the next twelve months.

On February 20, 2014, we entered into a $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the “new credit facility”). Our ability to borrow funds and obtain letters of credit under the new credit facility is conditioned upon, among other things, the closing of the Contribution and the prior or concurrent termination of our existing credit facility. Upon the termination of the existing credit facility, the liens securing the existing credit facility will be released and our subsidiaries will no longer guarantee our indebtedness and will be released as guarantors under the indentures governing our Senior Notes (as defined below).

The new credit facility will mature on the fifth anniversary of the initial funding date, unless we request, and the requisite lenders agree, to extend it pursuant to its terms. The new credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the new credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA will increase to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under the new credit facility bear interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent’s prime rate) plus an applicable margin. The applicable margins vary depending on our credit rating. Upon breach by us of certain covenants governing the new credit facility, amounts outstanding under the new credit facility, if any, may become due and payable immediately.

Senior Unsecured Notes. On February 10, 2010, we issued, together with Crosstex Energy Finance Corporation, $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "2018 Notes") due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity including the original issue discount (OID). Interest payments on the 2018 Notes are due semi-annually in arrears in February and August. On May 24, 2012, we issued, together with Crosstex Energy Finance Corporation, $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes" and together with the 2018 Notes, the "Senior Notes") due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments on the 2022 Notes are due semi-annually in arrears in June and December.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to:

- sell assets including equity interests in our subsidiaries;
- pay distributions on, redeem or repurchase units or redeem or repurchase our subordinated debt (as discussed in more detail below);
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; or
- engage in certain business activities.

The indentures provide that if our fixed charge coverage ratio (the ratio of consolidated cash flow to fixed charges, which generally represents the ratio of adjusted EBITDA to interest charges with further adjustments as defined per the indenture) for the most recently ended four full fiscal quarters is not less than 2.0 to 1.0, we will be permitted to pay distributions to our unitholders in an amount equal to available cash from operating surplus (each as defined in our partnership agreement) with respect to our preceding fiscal quarter plus a number of items, including the net cash proceeds received by us as a capital contribution or from the issuance of equity interests since the date of the indenture, to the extent not previously expended. If our fixed charge coverage ratio is less than 2.0 to 1.0, we will be able to pay distributions to our unitholders in an amount equal to a specified basket (less amounts previously expended pursuant to such basket), plus the same number of items discussed in the preceding sentence to the extent not previously expended. We expect to be in compliance with this covenant for at least the next twelve months.

If the Senior Notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, many of the covenants discussed above will terminate.

On or after February 15, 2014, we may redeem all or a part of the 2018 Notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on February 15, 2014, 102.219% for the twelve-month period beginning February 15, 2015 and 100.00% for the twelve-month period beginning on February 15, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the notes.

We may redeem up to 35% of the 2022 Notes at any time prior to June 1, 2015 in an amount not greater than the cash proceeds from one or more equity offerings at a redemption price of 107.125% of the principal amount of the 2022 Notes (plus accrued and unpaid interest to the redemption date) provided that

- at least 65% of the aggregate principal amount of the 2022 Notes remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 180 days of the date of the closing of the equity offering.

Pursuant to the foregoing, on January 3, 2014, we instructed the trustee to deliver a notice of redemption for approximately $53.5 million in aggregate principal amount of the 2022 Notes (the “Redeemed Notes”), representing approximately 21% of the aggregate principal amount of the outstanding 2022 Notes. The Redeemed Notes were redeemed effective as of February 2, 2014 for a total redemption price equal to $1,083.32 per $1,000 principal amount redeemed. Following the completion of the redemption, approximately $196.5 million aggregate principal amount of the 2022 Notes remain outstanding.

Prior to June 1, 2017, we may redeem all or a part of the remaining 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date.

On or after June 1, 2017, we may redeem all or a part of the remaining 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Each of the following is an event of default under the indentures:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures;
- our or any of our subsidiaries' default under other indebtedness that exceeds a certain threshold amount;
- failures by us or any of our subsidiaries to pay final judgments that exceed a certain threshold amount; and
- bankruptcy or other insolvency events involving us or any of our material subsidiaries.

If an event of default relating to bankruptcy or other insolvency events occurs, the Senior Notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the Senior Notes may accelerate the maturity of the Senior Notes and exercise other rights and remedies.

Successful completion of the Contribution and the Mergers would trigger a mandatory repurchase offer under the terms of the indenture governing our 2018 Notes at a purchase price equal to 101% of the aggregate principal amount of the 2018 Notes repurchased, plus accrued and unpaid interest, if any. In certain circumstances, completion of the Contribution and the Mergers also could trigger a mandatory repurchase offer under the terms of the indenture governing our 2022 Notes if, within 90 days of consummation of the transactions, we experience a rating downgrade of the 2022 Notes by either Moody's or S&P. We intend to fulfill our obligations with respect to the mandatory repurchase offer of the 2018 Notes and, if necessary, the 2022 Notes, following the closing of the Contribution and the Mergers in accordance with the terms of the applicable indenture.

Credit Risk

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders.

Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry's labor and material costs remained relatively unchanged in 2011, 2012 and 2013. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us, see "Item 1. Business—Environmental Matters."

Contingencies

At times, our gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, we (or our subsidiaries) are party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution, if any, in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations or financial condition.

From time to time, owners of property located near processing facilities or compression facilities file lawsuits against us. These suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. We have appealed the matter and have posted a bond to secure the judgment pending its resolution. We have accrued a $2.0 million liability related to this matter. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations or financial condition.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans, but was removed to federal court. The amount of damages is unspecified. The Partnership's subsidiary, Crosstex LIG, LLC, is one of the named defendants as the owner of pipelines in the area. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included in this Form 10-K constitute forward-looking statements, including but not limited to statements identified by the words "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "intend," "estimate" and "expect" and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Form 10-K, the risk factors set forth in "Item 1A. Risk Factors" may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

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

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas, NGLs and crude oil. In addition, we are also exposed to the risk of changes in interest rates on floating rate debt.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter (“OTC”) derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement mandates in new legislation to cause significant portions of derivatives markets to clear through clearinghouses. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any future new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all.

Our revenues could be adversely affected if a consequence of the legislation and regulations is lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under three main types of contractual arrangements:

1. *Processing margin contracts*: Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or "PTR". Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us, or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.
2. *Percent of liquids contracts*: Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of liquids contracts, but do decline during periods of low NGL prices.
3. *Fee based contracts*: Under these contracts we have no commodity price exposure and are paid a fixed fee per unit of volume that is processed. Included in these contracts are margins earned on our Cajun-Sibon pipeline and fractionated at one of our fractionation facilities.

Gas processing margins by contract types and gathering and transportation margins as a percent of total gross operating margin for the comparative year-to-date periods are as follows:

	Years Ended December 31,		
	2013	2012	2011
Gathering, transportation and crude handling margin	62.0%	63.8%	56.6%
Gas processing margins:			
Processing margin	5.6%	9.6%	19.3%
Percent of liquids	9.0%	7.5%	10.7%
Fee based (a)	23.4%	19.1%	13.4%
Total gas processing	38.0%	36.2%	43.4%
Total	100.0%	100.0%	100.0%

(a) Includes gross operating margins from our Cajun-Sibon Phase I operations.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a risk management committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLs using over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our risk management committee.

We have hedged our exposure to fluctuations in prices for natural gas and NGL volumes produced for our account. We hedge our exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options.

The following table sets forth certain information related to derivative instruments outstanding at December 31, 2013 mitigating the risks associated with the gas processing and fractionation components of our business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service ("OPIS"). The relevant index price for Natural Gas is Henry Hub Gas Daily is as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume		We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)	
January 2014 - December 2016	Ethane	1,129	(MBbls)	Index	$0.2917/gal	$	(603)
January 2014 - December 2016	Propane	1,320	(MBbls)	Index	$1.0455/gal		(235)
January 2014 - December 2014	Normal Butane	46	(MBbls)	Index	$1.2768/gal		(101)
January 2014 - December 2014	Natural Gasoline	30	(MBbls)	Index	$1.9734/gal		(136)
January 2014 - December 2014	Natural Gas	797	(MMBtu/d)	$4.0655/MMBtu*	Index		40
						$	(1,035)

* weighted average

We are subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transport services. Approximately 3.3% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing natural gas at a percentage of index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices.

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

As of December 31, 2013, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $1.1 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $4.8 million in the net fair value of these contracts as of December 31, 2013.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At December 31, 2013, we had $155.0 million outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $1.6 million for the year.

At December 31, 2013 and 2012, we had total fixed rate debt obligations of $967.2 million and $965.3 million, respectively. The balance at December 31, 2013 is related to our 2018 Notes and 2022 Notes of $717.2 million and $250.0 million with interest rates of 8.875% and 7.125%, respectively. The balance at December 31, 2012 is related to our 2018 Notes and 2022 Notes of $715.3 million and $250.0 million with interest rates of 8.875% and 7.125%, respectively. The fair value of the fixed rate obligations for the 2018 Notes and 2022 Notes was approximately $762.9 million and $285.3 million, respectively, as of December 31, 2013, and $786.6 million and $261.3 million, respectively as of December 31, 2012. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of the 2018 Notes and 2022 Notes by $25.3 million and $17.0 million, respectively, based on the debt obligations as of December 31, 2013.

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

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 through F-43 of this Report and are incorporated herein by reference.

Item 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (December 31, 2013), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Internal Control Over Financial Reporting

See "Management's Report on Internal Control over Financial Reporting" on page F-2.

Item 9B. ***Other Information***

Compensation Matters

On February 27, 2014, the compensation committee (the “Committee”) of the board of directors of Crosstex Energy GP, LLC (the “Board”) awarded $1,600,000 to Barry E. Davis under the Transaction Bonus Plan previously established by the Board, and the Committee and the Board approved allocations to the other named executive officers of the following awards under the Transaction Bonus Plan: William W. Davis $250,000; Joe A. Davis $800,000; Michael J. Garberding $800,000; and Stan Golemon $200,000. For more information regarding the Transaction Bonus Plan and these awards, please see “Executive Compensation—Compensation Discussion and Analysis—Bonus Awards.”

Also on February 27, 2014, the Committee and the Board, together with the compensation committee and the board of directors of Crosstex Energy, Inc., awarded and/or approved allocations of awards, as applicable, of $257,335, $113,548 and $195,702 to Barry E. Davis, Joe A. Davis and Michael J. Garberding, respectively, pursuant to the cash bonus pool established to provide consideration for such individuals’ agreement to waive certain rights with respect to the acceleration and vesting of awards in connection with the proposed business combination with Devon. For more information regarding these waivers and this cash bonus pool, please see “Executive Compensation—Compensation Discussion and Analysis—Potential Payments Upon Termination and a Change of Control.”

Additionally, on February 25, 2014, our General Partner entered into an employment agreement amendment with each of William W. Davis, Joe A. Davis and Michael J. Garberding to extend the term of each such individual’s employment agreement until August 31, 2014. All other terms of the employment agreements remain unchanged. For more information regarding the employment agreements, please see “Executive Compensation—Compensation Discussion and Analysis—Employment and Severance Agreements.”

Partnership Agreement Amendment

On February 27, 2014, the Board adopted Amendment No. 5 to our Sixth Amended and Restated Agreement of Limited Partnership, as amended to date (the "Partnership Agreement"), to reduce the trading volume that is required with respect to our common units in order for us to force the conversion of our outstanding Series A Convertible Preferred Units (the "preferred units"). As amended, we have the right to force conversion of the preferred units beginning on the business day following the distribution for the quarter ended December 31, 2013 (which was February 12, 2014) if (i) the daily volume weighted average trading price of the common units is greater than $12.75 per unit for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion, and (ii) the average trading volume of common units exceeds 215,000 common units for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion. On February 27, 2014, we delivered a notice of conversion of all outstanding preferred units to GSO Crosstex Holdings, LLC ("GSO"), the sole holder of our preferred units, and issued 17,095,134 common units to GSO pursuant to an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 3(a)(9) thereof.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

As is the case with many publicly traded partnerships, we do not have officers, directors or employees. Our operations and activities are managed by our general partner, Crosstex Energy GP, LLC. Our operational personnel are employees of the Operating Partnership. References to our officers, directors and employees are references to the officers, directors and employees of our general partner or the Operating Partnership.

Unitholders do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to the unitholders, as limited by our partnership agreement. As general partner, Crosstex Energy GP, LLC is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations on a non-recourse basis.

The following table shows information for the members of the board of directors (the "Board") and the executive officers of our general partner. Executive officers and directors serve until their successors are duly appointed or elected.

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis (1)	52	President, Chief Executive Officer and Director
William W. Davis (1)	60	Executive Vice President and Chief Operating Officer
Joe A. Davis (1)	53	Executive Vice President, General Counsel and Secretary
Michael J. Garberding	45	Executive Vice President and Chief Financial Officer
Stan Golemon	50	Senior Vice President-Engineering and Operations
Rhys J. Best**	67	Chairman of the Board and Member of the Conflicts, Finance* and Compensation Committees
Leldon E. Echols**	58	Director and Member of the Audit* and Finance Committees
Bryan H. Lawrence**	71	Director
Cecil E. Martin**	72	Director and Member of the Audit and Compensation* Committees
D. Dwight Scott**	50	Director and Member of the Compensation and Finance Committee
Kyle D. Vann**	66	Director and Member of the Governance, Conflicts* and Audit Committees

* Denotes chairman of committee.

** Denotes independent director.

(1) Not related.

Barry E. Davis, President, Chief Executive Officer and Director, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of our predecessor. Mr. Davis has served as director since our initial public offering in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by

Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University. Mr. Davis also serves as Chairman of the Board for Crosstex Energy, Inc. Mr. Davis is not related to William W. Davis or Joe A. Davis. Mr. Davis's leadership skills and experience in the midstream natural gas industry, among other factors, led the Board to conclude that he should serve as a director.

William W. Davis, Executive Vice President and Chief Operating Officer, joined our predecessor in September 2001 and has over 30 years of finance and accounting experience. Mr. Davis assumed the role of Chief Operating Officer in August 2011. Mr. Davis previously served as our Chief Financial Officer for over 8 years. Prior to joining our predecessor, Mr. Davis held various positions with Sunshine Mining and Refining Company from 1983 to September 2001, including Executive Vice President and Chief Financial Officer from 1991 to 2001. In addition, Mr. Davis served as Chief Operating Officer in 2000 and 2001. Mr. Davis graduated magna cum laude from Texas A&M University with a B.B.A. in Accounting and is a Certified Public Accountant. Mr. Davis is not related to Barry E. Davis or Joe A. Davis.

Joe A. Davis, Executive Vice President, General Counsel and Secretary, joined Crosstex in October 2005. He began his legal career in 1985 with the Dallas firm of Worsham Forsythe, which merged with the international law firm of Hunton & Williams in 2002. Most recently, he served as a partner in the firm's Energy Practice Group, and served on the firm's Executive Committee. Mr. Davis specialized in facility development, sales, acquisitions and financing for the energy industry, representing entrepreneurial start up/development companies, growth companies, large public corporations and large electric and gas utilities. He received his J.D. from Baylor Law School in Waco and his B.S. degree from the University of Texas in Dallas. Mr. Davis is not related to Barry E. Davis or William W. Davis.

Michael J. Garberding, Executive Vice President and Chief Financial Officer, joined our general partner in February 2008. Mr. Garberding assumed the role of Senior Vice President and Chief Financial Officer in August 2011 and the role of Executive Vice President and Chief Financial Officer in January 2013. Mr. Garberding previously led the finance and business development organization for the Partnership. Mr. Garberding has 20 years experience in finance and accounting. From 2002 to 2008, Mr. Garberding held various finance and business development positions at TXU Corporation, including assistant treasurer. In addition, Mr. Garberding worked at Enron North America as a Finance Manager and Arthur Andersen LLP as an Audit Manager. He received his Masters in Business Administration from the University of Michigan in 1999 and his B.B.A. in Accounting from Texas A&M University in 1991.

Stan Golemon, Senior Vice President—Engineering and Operations, joined our general partner in May 2008. Mr. Golemon has 25 years of experience in engineering, operations and commercial development in the midstream and exploration and production industries. From 1997 to 2008, Mr. Golemon held various midstream engineering, commercial, and management positions with Union Pacific Resources and its successor company Anadarko Petroleum Corporation including General Manager of Midstream Engineering and Engineering Supervisor. Mr. Golemon also spent 3 years with The Arrington Corporation consulting on sulfur recovery operations and Process Safety Management. Mr. Golemon began his career with ARCO Oil and Gas Company where he worked in plant engineering, onshore facilities engineering and offshore facilities engineering. Mr. Golemon graduated summa cum laude from Louisiana Tech University in 1985 with a Bachelor of Science degree in Chemical Engineering.

Rhys J. Best joined Crosstex Energy GP, LLC as a director in June 2004 and became Chairman of the Board in February 2009. Mr. Best was Chairman and Chief Executive Officer of Lone Star Technologies, Inc. until its merger into United States Steel Company in June of 2007. Mr. Best held the position of Chief Executive Officer from June 1998 and he assumed the additional responsibilities of Chairman in January 1999. He began his career at Lone Star as the President and Chief Executive Officer of Lone Star Steel Company, a position he held for eight years before becoming President and Chief Operating Officer of the parent company in 1997. Before joining Lone Star, Mr. Best held several leadership positions in the banking industry. Mr. Best also serves on the boards of Trinity Industries (NYSE: TRN), Cabot Oil & Gas Corp. (NYSE: COG), Commercial Metals Company (NYSE:CMC), Austin Industries, Inc., and MRC Global. Trinity is a leading diversified holding company with a subsidiary group that provides a variety of products and services for the transportation, industrial, construction and energy sectors. Cabot is an oil and gas exploration and production company. Commercial Metals Company manufactures, recycles and markets steel, other metals and related products. MRC Global is a large distributor of pipe, valves and fittings to the energy and industrial sectors. Austin Industries is a private company in the construction industry. Mr. Best is the chairman of the board of Austin Industries. Mr. Best graduated from the University of North Texas with a Bachelor of Business degree and later earned a Masters of Business Administration degree at Southern Methodist University. Mr. Best's experience in the financial sector and pipe manufacturing industry, leadership skills and experience as Chairman and Chief Executive Officer of public companies, among other factors, led the Board to conclude that he should serve as a director.

Leldon E. Echols joined Crosstex Energy GP, LLC as a director in January 2008. Mr. Echols is a private investor. Mr. Echols also currently serves as an independent director of Trinity Industries, Inc. (NYSE: TRN) and Holly Frontier

Corporation (NYSE: HFC), an independent petroleum refiner and marketer. Mr. Echols brings 30 years of financial and business experience to Crosstex. After 22 years with the accounting firm Arthur Andersen LLP, which included serving as managing partner of the firm's audit and business advisory practice in North Texas, Colorado and Oklahoma, Mr. Echols spent six years with Centex Corporation as executive vice president and chief financial officer. He retired from Centex Corporation in June 2006. Mr. Echols is also a member of the board of directors of Roofing Supply Group Holdings, Inc., a private company. He also served on the board of TXU Corporation where he chaired the Audit Committee and was a member of the Strategic Transactions Committee until the completion of the private equity buyout of TXU in October 2007. Mr. Echols earned a Bachelor of Science degree in accounting from Arkansas State University and is a Certified Public Accountant. He is a member of the American Institute of Certified Public Accountants and the Texas Society of CPAs. Mr. Echols has also served as a director of Crosstex Energy, Inc. since January 2008. Mr. Echols' accounting and financial experience and service as the Chief Financial Officer for a public company, among other factors, led the Board to conclude that he should serve as a director.

Bryan H. Lawrence joined Crosstex Energy GP, LLC as a director upon the completion of our initial public offering in December 2002 and served as Chairman of the Board until May 2008. Mr. Lawrence is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships, which make investments in companies engaged in the energy industry. The Yorktown partnerships were formerly affiliated with the investment firm of Dillon, Read & Co. Inc., where Mr. Lawrence had been employed since 1966, serving as a Managing Director until the merger of Dillon Read with SBC Warburg in September 1997. Mr. Lawrence also serves as a director of Hallador Petroleum Company (OTC BB: HPCO.OB), Star Gas Partners L.P. (NYSE: SGU), Approach Resources, Inc. (NASDAQ: AREX) and certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests. Mr. Lawrence is a graduate of Hamilton College and also has an M.B.A. from Columbia University. Mr. Lawrence has also served as a director of Crosstex Energy, Inc. since 2000. Mr. Lawrence's financial and investment experience and experience in the energy industry, among other factors, led the Board to conclude that he should serve as a director.

Cecil E. Martin, Jr. joined Crosstex Energy GP, LLC as a director in January 2006. He has been an independent residential and commercial real estate investor since 1991. From 1973 to 1991 he served as chairman of the public accounting firm Martin, Dolan and Holton in Richmond, Virginia. He began his career as an auditor at Ernst and Ernst. He holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant. Mr. Martin also serves on the board as lead director and as chairman of the audit committee of Comstock Resources, Inc. (NYSE: CRK), an independent energy company engaged in oil and gas acquisitions, exploration and development. Mr. Martin served on the board and as chairman of the audit committee for Bois d'Arc Energy, Inc. (NYSE: BDE) until its merger into Stone Energy Corporation (NYSE: SGY) in 2008. Mr. Martin also serves on the board as chairman of the audit committee of Garrison Capital, LLC (NASDAQ: GARS). Mr. Martin also has served as a director of Crosstex Energy, Inc. since January 2006. Mr. Martin's accounting and financial experience, experience on audit committees of other public companies, and related industry experience, among other factors, led the Board to conclude that he should serve as a director.

Donald (Dwight) Scott joined Crosstex Energy GP, LLC as a director in January 2010. He is a Senior Managing Director of GSO Capital Partners LP and head of GSO Capital Partners' Energy Practice. Mr. Scott focuses on investments in the energy and power markets and is a member of GSO's Investment Committee. Before joining GSO in 2005, Mr. Scott was an Executive Vice President and Chief Financial Officer of El Paso Corporation (NYSE: EP). Prior to joining El Paso, Mr. Scott served as a managing director in the energy investment banking practice of Donaldson, Lufkin & Jenrette. Mr. Scott earned a BA from the University of North Carolina at Chapel Hill and a MBA from The University of Texas at Austin. He is currently a director of 3 Bear Tracker, LLC, Energy Alloys LLC and Giant Cement Holding Inc. Mr. Scott is a member of the Board of Trustees of KIPP, Inc. Mr. Scott was selected as a director pursuant to a Board Representation Agreement entered into on January 19, 2010 between us, our general partner, CEI and GSO Crosstex Holdings LLC. Pursuant to the Board Representation Agreement, each of the Crosstex entities agreed to take all actions necessary or advisable to cause one director serving on the Board to be designated by GSO Crosstex Holdings LLC, in its sole discretion. Mr. Scott brings to the Board investment, financial and industry experience.

Kyle D. Vann joined Crosstex Energy GP, LLC as a director in April 2006. Mr. Vann began his career with Exxon Corporation in 1969. After ten years at Exxon, he joined Koch Industries and served in various leadership capacities, including senior vice president from 1995-2000. In 2001, he then took on the role of CEO of Entergy-Koch, LP, an energy trading and transportation company, which was sold in 2004. Currently, Mr. Vann continues to consult with Entergy and is an executive advisor to CCMP Capital Advisors, LLC. He also serves on the boards of Texon, L.P., Chaparral Energy and Legacy Reserves, LLC (NASDAQ: LGCY). He also serves on the board of directors for Mars Hill Productions and Generous Giving, which are private, charitable non-profits. Mr. Vann graduated from the University of Kansas with a Bachelor of Science degree in chemical engineering. He is a member of the Board of Advisors for the University of Kansas School of Engineering (where he was a recipient of the Distinguished Engineering Service Award).

Independent Directors

Messrs. Best, Echols, Lawrence, Martin, Scott and Vann qualify as "independent" directors in accordance with the published listing requirements of The NASDAQ Global Select Market (NASDAQ). The NASDAQ independence definition includes a series of objective tests, such as that the director is not an employee of the company and has not engaged in various types of business dealings with the company. In addition, as further required by the NASDAQ rules, the Board has made a subjective determination as to each independent director that no relationships exist which, in the opinion of the Board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

In addition, the members of the Audit Committee also each qualify as "independent" under special standards established by the SEC for members of audit committees, and the Audit Committee includes at least one member who is determined by the Board to meet the qualifications of an "audit committee financial expert" in accordance with SEC rules, including that the person meets the relevant definition of an "independent" director. Messrs. Echols and Martin are both independent directors who have been determined to be audit committee financial experts. Unitholders should understand that this designation is a disclosure requirement of the SEC related to experience and understanding with respect to certain accounting and auditing matters. The designation does not impose any duties, obligations or liabilities that are greater than those generally imposed on a member of the Audit Committee and Board, and the designation of a director as an audit committee financial expert pursuant to this SEC requirement does not affect the duties, obligations or liabilities of any other member of the Audit Committee or Board.

Board Committees

The Board has, and appoints the members of, standing Audit, Compensation, Finance, Governance and Conflicts Committees. Each member of the Audit, Compensation, Finance, Governance and Conflicts Committees is an independent director in accordance with NASDAQ standards described above. Each of the board committees has a written charter approved by the board. Copies of the charters and our Code of Business Conduct and Ethics are available to any person, free of charge, at our web site: www.crosstexenergy.com.

The Audit Committee, comprised of Messrs. Echols (chair), Martin and Vann, assists the Board in its general oversight of our financial reporting, internal controls and audit functions, and is directly responsible for the appointment, retention, compensation and oversight of the work of our independent auditors.

The Finance Committee, comprised of Messrs. Best (chair), Echols and Scott, assists the Board in discharging its duties in connection with financial planning and significant financial transactions, and is directly responsible for reviewing and evaluating distribution policy, transactions that involve issuance of equity or debt securities, oversight of credit facilities, and review of material transactions.

The Conflicts Committee, comprised of Messrs. Vann (chair) and Best, reviews specific matters that the Board believes may involve conflicts of interest between our general partner and Crosstex Energy, L.P. The Conflicts Committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not directors, officers or employees of Crosstex Energy, Inc., the owner of our general partner. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

The Compensation Committee, comprised of Messrs. Martin (chair), Scott and Best, oversees compensation decisions for the officers of our general partner as well as the compensation plans described herein.

The Governance Committee, comprised of Mr. Vann, reviews matters involving governance including assessing the effectiveness of current policies, monitoring industry developments, recommending committee structures within the Board, managing the assessment process of the Board and individual directors, annually reviewing and recommending the compensation of directors and performing other duties as delegated from time to time. The Governance Committee is responsible for identifying Board candidates and making recommendations to the Board regarding the election of directors. When Board vacancies are created or occur, the Governance Committee reviews applicable legal requirements, listing requirements and the competencies of the continuing directors, and develops a candidate profile that identifies any specific competencies or expertise that the Committee believes the Board needs to add or supplement. The Governance Committee solicits referrals from existing directors and other industry contacts to identify candidates that possess those specific competencies or that specific expertise. In the past, the Governance Committee has also used search firms to identify potential candidates. The Governance Committee then interviews interested candidates to assess the candidate's qualifications and to assess the ability of the candidate to work with the other directors. The Governance Committee evaluates candidates and makes its recommendations on the basis of the qualifications of each candidate individually, including the candidate's reputation, professional experience, experience in the same or related industries, service on other public company boards, other time commitments, the diversity of the Board members' backgrounds and professional experience, and the ability of the candidate to work with other Board members. Under the terms of our partnership agreement, unitholders do not participate in the appointment or election of the directors of our general partner.

Board Meetings and Attendance

Our Board met 13 times in 2013. All incumbent directors attended in excess of 75% of the total number of meetings of our Board and committees of our Board on which they served.

Code of Ethics

Our general partner has adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers and directors with regard to Partnership-related activities. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. A copy of the Code of Ethics is available to any person, free of charge, at our website www.crosstexenergy.com. If any substantive amendments are made to the Code of Ethics or if we or our general partner grants any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our general partner's executive officers and directors, we will disclose the nature of such amendment or waiver on our website.

Section 16(a)—Beneficial Ownership Reporting Compliance

Based on our records, except as set forth in the following, we believe that during 2013 all reporting persons complied with the Section 16(a) filing requirements applicable to them. Forms 4 reporting grants of restricted incentive units under Crosstex Energy GP, LLC's long term incentive plan were filed late on behalf of Rhys J. Best, Kyle D. Vann, Leldon E. Echols and Cecil E. Martin, Jr. on July 2, 2013.

Reimbursement of Expenses of our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation in connection with its management of our partnership. However, our general partner performs services for us and is reimbursed by us for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Item 11. *Executive Compensation*

We do not directly employ any of the persons responsible for managing our business. Crosstex Energy GP, LLC, our general partner, manages our operations and activities, and its Board and officers make decisions on our behalf. The compensation of the executive officers of Crosstex Energy GP, LLC is determined by the Board upon the recommendation of its Compensation Committee. The compensation of the directors of Crosstex Energy GP, LLC is determined by the Board upon the recommendation of its Governance Committee. Our named executive officers also serve as officers of Crosstex Energy, Inc. and the compensation of the named executive officers discussed below reflects total compensation for services to all Crosstex entities. We pay or reimburse all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Crosstex Energy, Inc. currently pays a monthly fee to Crosstex Energy GP, LLC to cover its portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Based on the information that we track regarding the amount of time spent by each of our named executive officers on business matters relating to Crosstex Energy, L.P., we estimate that such officers devoted the following percentage of their time to the business of Crosstex Energy, L.P. and to Crosstex Energy, Inc., respectively, for 2013:

Executive Officer or Director	Percentage of Time Devoted to Business of Crosstex Energy, L.P.	Percentage of Time Devoted to Business of Crosstex Energy, Inc.
Barry E. Davis	80%	20%
William W. Davis	100%	—
Joe A. Davis	74%	26%
Michael J. Garberding	74%	26%
Stan Golemon	100%	—

Compensation Committee Report

Each member of Crosstex Energy GP, LLC's Compensation Committee is an independent director in accordance with NASDAQ standards. The Committee has reviewed and discussed with management the following section titled "Compensation Discussion and Analysis." Based upon its review and discussions, the Committee has recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Cecil E. Martin (Chairman)
Rhys J. Best
D. Dwight Scott

Compensation Discussion and Analysis

The Charter of the Compensation Committee of the Board includes the following:

- The Committee has general oversight responsibility for the Company's compensation plans, policies and programs. This general oversight responsibility includes reviewing and approving compensation policies and practices for all employees, overall payroll, bonus plans, overall bonus payouts, setting bonus targets and other general compensation matters.
- Not less than annually, the Committee will review the Company's executive compensation plans and policies. The Committee will review the corporate goals and objectives relevant to the compensation of the Chief Executive Officer, the other executive officers and each other senior officer that the Committee or the Board may designate (collectively referred to as the "Executive Officers"). The Committee will evaluate the performance of the Chief Executive Officer, and, together with the Chief Executive Officer, the performance of each other Executive Officer. The Committee will at least annually review each Executive Officer's base compensation, bonus, awards under the Company's Long Term Incentive Plans and any other compensation and make recommendations to the Board regarding each Executive Officer's compensation. The Chief Executive Officer cannot be present during any voting or deliberations by the Committee regarding his or her compensation.
- The Committee will review and oversee the Company's succession plans and leadership development programs for the Chief Executive Officer and the other Executive Officers, including reviewing from time to time reports and presentations regarding human resources, executive development, staffing, training, performance management, career development and other related matters as necessary.
- The Committee will review and approve the terms of any employment contracts, severance agreements or other contracts with any Executive Officer, provided that the Board reserves to itself the approval of the compensation of the Executive Officers.

In order to compete effectively in our industry, it is critical that we attract, retain and motivate leaders that are best positioned to deliver financial and operational results that benefit our unitholders. It is the Committee's responsibility to design and administer compensation programs that achieve these goals and to make recommendations to the Board to approve and adopt these programs.

Compensation Philosophy and Principles.

Our executive compensation is designed to attract, retain and motivate top-tier executives and align their individual interests with the interests of our unitholders. The compensation of each of our executives is comprised of base salary, bonus opportunity and restricted equity grants or option awards under long term incentive plans. The Committee's philosophy is to generally target the 50th percentile of our Peer Group (discussed below) for base salaries, target the 50th percentile of our Peer Group for bonuses (but retain discretion to reduce or increase bonus amounts to address individual performance) and to provide executives the opportunity to earn long-term compensation, in the form of equity, in the top quartile relative to our Peer Group.

The Committee considers the following principles in determining the total compensation of the named executive officers:

- in order to achieve its goals, it is critical that we attract, retain and motivate highly qualified executive officers;
- base salary and bonus opportunities must be competitive in order to attract, retain and motivate highly qualified executive officers;
- equity incentive compensation should represent a significant portion of the executive's total compensation in order to retain and incentivize highly qualified executives and align their individual long term interests with the interests of unitholders;

- compensation programs must be sufficiently flexible to address special circumstances, which include payments under retention plans specifically targeted to retain highly qualified officers during challenging times; and
- the overall compensation program should drive performance and reward contributions in support of our business strategies and achievements.

Compensation Methodology.

Annually, the Committee reviews our executive compensation program in total and each element of compensation specifically. The review includes an analysis of the compensation practices of other companies in our industry, the competitive market for executive talent, the evolving demands of the business, specific challenges that we may face, and individual contributions to our partnership. The Committee recommends to the Board adjustments to the overall compensation program and to its individual components as the Committee determines necessary to achieve our goals. The Committee periodically retains consultants to assist in its review and to provide input regarding its compensation program and each of its elements.

In 2013, the Committee retained Meridian Compensation Partners, LLC ("Meridian") as its independent compensation consultant to conduct a compensation review and advise the Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees of our general partner. In particular, Meridian assisted the Committee's decision making with respect to executive and director compensation matters, including providing advice on our executive pay philosophy, compensation peer group, incentive plan design and employment agreement design, providing competitive market studies, and apprising the Committee about emerging best practices and changes in the regulatory and governance environment. The Committee selected Meridian due to its long history, depth of resources and objective perspective. Meridian provided information to the Committee regarding the compensation programs of the Crosstex entities for 2013. Meridian's work for the Committee did not raise any conflicts of interest in 2013.

With respect to compensation objectives and decisions regarding the named executive officers for fiscal 2013, the Committee has reviewed market data with respect to peer companies provided by Meridian in determining relevant compensation levels and compensation program elements for our named executive officers, including establishing their respective base salaries. In addition, Meridian has provided guidance on current industry trends and best practices to the Committee. The market data that the Committee reviewed included the base salary, bonus structure, bonus methodology and short and long-term compensation elements paid to executive officers in similar positions at our peer companies. For 2013, the Committee and Meridian collaborated to identify the following companies as "Peer Companies" for comparison purposes: Access Midstream Partners, L.P., Atlas Pipeline Partners, L.P., Buckeye Partners, L.P., DCP Midstream Partners, L.P., Eagle Rock Energy Partners, L.P., Magellan Midstream Partners, L.P., Targa Resources Partners LP, Regency Energy Partners, L.P., MarkWest Energy Partners, L.P., Western Gas Partners, L.P., Genesis Energy, L.P., NGL Energy Partners, L.P., Semgroup Corp., and Martin Midstream Partners, L.P. We believe that this group of companies is representative of the industry in which we operate and the individual companies were chosen because of such companies' relative position in our industry, relative size/market capitalization, relative complexity of the business, similar organizational structure, competition for similar executive talent and the named executive officers' roles and responsibilities.

In addition, the Committee has reviewed various relevant compensation surveys with respect to determining compensation for the named executive officers. In determining the long-term incentive component of compensation of the senior executives of Crosstex Energy GP, LLC (including the named executive officers), the Committee considers individual performance and relative equity holder benefit, the value of similar incentive awards to senior executives at comparable companies, awards made to the company's senior executives in past years, the value of all unvested awards held by the executive and such other factors as the Committee deems relevant.

Elements of Compensation.

For fiscal year 2013, the principal elements of compensation for the named executive officers were the following:

- base salary;
- annual bonus plan awards;
- long-term incentive plan awards; and
- retirement and health benefits.

The Committee reviews and makes recommendations regarding the mix of compensation, both among short- and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the named executive officers. We believe that the mix of base salary, annual bonus awards, awards under the long-term incentive plan, retirement and health benefits and perquisites and other compensation fit our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies that we require.

Base Salary. The Committee recommends base salaries for the named executive officers based on the historical salaries for services rendered to Crosstex Energy GP, LLC and its affiliates, market data and responsibilities of the named executive officers. Salaries are generally determined by considering the employee's performance and prevailing levels of compensation in areas in which a particular employee works. As discussed above, after giving effect to the monthly reimbursement payment received from Crosstex Energy, Inc., the remaining portion of the base salaries of the named executive officers was allocated to us by Crosstex Energy GP, LLC as general and administration expenses. The base salaries paid to our named executive officers during fiscal year 2013 are shown in the Summary Compensation Table on page 83. The base salaries payable to our named executive officers for fiscal 2014 are currently unchanged from the base salaries for fiscal 2013; however, upon the recommendation of the Committee, the Board has approved the following base salaries for our named executive officers that will become effective upon the closing of the Mergers and the Contribution (the "Closing"): Barry E. Davis $600,000; William W. Davis $395,000; Joe A. Davis $375,000; Michael J. Garberding $400,000; and Stan Golemon $300,000.

Bonus Awards. The Committee oversees the Annual Bonus Plan and makes recommendations regarding bonuses to be awarded to each of the named executive officers. The Annual Bonus Plan is applicable to all employees. Under the plan, bonuses are awarded to our named executive officers based on a formulaic approach that utilizes a performance metric that is tied to adjusted EBITDA (see Item 6. "Selected Financial Data" for definition) as a guideline. The same adjusted EBITDA performance metric is used as a guideline for bonuses for all employees. The adjusted EBITDA goals are determined at the beginning of the year by the Board upon the recommendation of the Committee. Discretionary bonuses in addition to bonuses under the Annual Bonus Plan are awarded from time to time by the Committee to reward outstanding service to the company.

The final amount of bonus for each named executive officer is determined by the Committee and recommended for approval by the Board, based upon the Committee's assessment of whether such executive met his or her performance objectives established at the beginning of the performance period. These performance objectives include the quality of leadership within the named executive officer's assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer and the named executive officer's contribution to, and enhancement of, the desired company culture. These performance objectives are reviewed and evaluated by the Committee as a whole. All of our named executive officers met or exceeded their personal performance objectives for 2013. Accordingly, the Committee and the Board awarded bonuses to the named executive officers ranging from approximately 45% to 94% of base salary for 2013. Such awards were paid in the form of stock awards that immediately vest and were allocated 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc.

The Committee believes that a portion of executive compensation must remain discretionary and exercises its discretion with respect to bonus awards payable to its named executive officers. The Committee may exercise its discretion to reduce the amount calculated under the formula as described above, or to supplement the amount to reward or address extraordinary individual performance, challenges and opportunities not reasonably foreseeable at the beginning of a performance period, internal equities, and external competition or opportunities.

Target adjusted EBITDA is based upon a standard of reasonable market expectations and company performance, and varies from year to year. Several factors are reviewed in determining target adjusted EBITDA, including market expectations, internal forecasts and available investment opportunities. For 2013, our adjusted EBITDA levels for bonuses were $200.0 for minimum equity bonuses, $220.0 million for minimum cash bonuses, $235.0 million for target cash and equity bonuses and $270.0 million for maximum cash and equity bonuses. The 2013 plan provided for named executive officers to receive bonus payouts of 6% to 13% of base salary at the minimum threshold, payouts ranging from 60% to 125% of base salary at the target level and payouts ranging from 90% to 188% of base salary at the maximum level.

Additionally, on January 14, 2014, the Board, upon the recommendation of the Committee, approved and authorized us to fund a cash bonus plan in an aggregate amount of up to $10.0 million (the "Transaction Bonus Plan") to reward a broad base of employees, including the named executive officers, for the transactions with Devon. Awards made under the Transaction Bonus Plan are contingent upon the Closing. In February 2014, the Committee awarded $1,600,000 to Barry E. Davis under the Transaction Bonus Plan, and the Committee and the Board approved allocations to the other named executive officers of the following awards under the Transaction Bonus Plan: William W. Davis $250,000; Joe A. Davis $800,000; Michael J. Garberding $800,000; and Stan Golemon $200,000.

Long-Term Incentive Plans. Our officers and directors are eligible to participate in long-term incentive plans adopted by each of Crosstex Energy GP, LLC and Crosstex Energy, Inc. We believe that equity awards are instrumental in attracting, retaining, and motivating employees, and align the interests of our officers and directors with the interests of the unitholders. The Board, at the recommendation of the Committee, approves the grants of Partnership units or options to our executive officers. The Committee believes that equity compensation should comprise a significant portion of a named executive officer's compensation, and considers a number of factors when determining the grants to each individual. The considerations include: the general goal of allowing the named executive officer the opportunity to earn aggregate equity compensation (comprised of Partnership units and Crosstex Energy, Inc. stock) in the upper quartile of our Peer Group; the amount of unvested equity held by the individual executive; the executive's performance; and other factors as determined by the Committee.

A discussion of each plan follows:

Crosstex Energy GP, LLC Long-Term Incentive Plan. Crosstex Energy GP, LLC has adopted a long-term incentive plan (the "Plan") for employees, consultants and independent contractors of Crosstex Energy GP, LLC and its affiliates and outside directors of our Board who perform services for us. The long-term incentive plan is administered by the Compensation Committee of Crosstex Energy GP, LLC and permits the grant of awards, which may be awarded in the form of restricted incentive units or unit options. On May 9, 2013, the Partnership's unitholders approved the amendment and restatement of the Plan, which increased the number of common units representing limited partner interests in the Partnership authorized for issuance under the Plan by 3,470,000 common units to an aggregate of 9,070,000 common units and made certain other technical amendments. Of the 9,070,000 common units that may be awarded under the long-term incentive plan, 3,754,195 common units remain eligible for future grants by Crosstex Energy GP, LLC as of January 1, 2014. The long-term compensation structure is intended to align the employee's performance with long-term performance for our unitholders.

The Board, in its discretion, may terminate or amend the Plan at any time with respect to any units for which a grant has not yet been made. The Board also has the right to alter or amend the Plan or any part of the Plan from time to time, including increasing the number of units that may be granted subject to the approval requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits of the participant without the consent of the participant.

- *Unit Options.* The long-term incentive plan currently permits the grant of options covering common units. Under current policy all unit option grants will have an exercise price that is not less than 100% of the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the Committee. In addition, the unit options will become exercisable upon a change in control of us or our general partner, as discussed below under "—Potential Payments Upon a Change of Control or Termination." Upon exercise of a unit option, Crosstex Energy GP, LLC will acquire common units in the open market or directly from us or any other person or use common units already owned, or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the difference between the cost incurred by it in acquiring these common units and the proceeds received by it from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and Crosstex Energy GP, LLC will pay us the proceeds it received from the optionee upon exercise of the unit option. The unit options granted pursuant to the Plan have been designed to furnish additional compensation to employees, consultants, independent contractors and directors and to align their economic interests with those of common unitholders.

- *Restricted Incentive Units.* Awards of restricted incentive units are rights that entitle the grantee to receive common units of the Partnership upon the vesting of such restricted incentive units. The Committee will determine the terms, conditions and limitations applicable to any awards of restricted incentive units. Awards of restricted incentive units will have a vesting period established in the sole discretion of the Committee, which may include, without limitation, accelerated vesting upon the achievement of specified performance goals. In addition, the restricted incentive units will vest upon a change of control of us or of our general partner, as discussed below under "—Potential Payments Upon a Change of Control or Termination." Common units to be delivered upon the vesting of restricted incentive units may be common units acquired by Crosstex Energy GP, LLC in the open market, common units already owned by Crosstex Energy GP, LLC, common units acquired by Crosstex Energy GP, LLC directly from us or any other person or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted incentive units, the total number of common units outstanding will increase. The Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted incentive units which entitles the grantee to distributions attributable to the restricted incentive units prior to vesting of such units. We intend the issuance of the common units upon vesting of the restricted incentive units under the Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under current policy, Plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

The total value of the equity compensation granted to our named executive officers generally has been allocated 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. For fiscal year 2013, Crosstex Energy GP, LLC granted 63,113, 30,468, 30,604, 49,462 and 19,727 restricted incentive units to Barry E. Davis, William W. Davis, Joe A. Davis, Michael J. Garberding and Stan Golemon, respectively. All restricted incentive units that we grant are charged against earnings according to FASB Accounting Standards Codification 718—"Compensation—Stock Compensation" (ASC 718).

Crosstex Energy, Inc. Long-Term Incentive Plans. The Crosstex Energy, Inc. long-term incentive plans provide for the award of stock options, restricted stock, restricted stock units and other awards (collectively, "Awards") for up to 8,975,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2014, approximately 2,464,665 shares remained available under the long-term incentive plans for future issuance to participants. A participant may not receive in any calendar year options or stock awards relating to more than 250,000 shares of common stock. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Shares of common stock underlying Awards that are forfeited, terminated or expire unexercised become immediately available for additional Awards under the applicable long-term incentive plan.

The Compensation Committee (the "CEI Committee") of Crosstex Energy, Inc.'s board of directors (the "CEI Board") administers its long-term incentive plans. The administrator has the power to determine the terms of the options or other awards granted, including the exercise price of the options or other awards, the number of shares subject to each option or other award, the exercisability thereof and the form of consideration payable upon exercise. In addition, the administrator has the authority to grant waivers of the applicable long-term incentive plan terms, conditions, restrictions and limitations. Awards may be granted to employees, consultants and outside directors of Crosstex Energy, Inc.

The CEI Committee will determine the type or types of Awards made under the plans and will designate the individuals who are to be the recipients of Awards. Each Award may be embodied in an agreement containing such terms, conditions and limitations as determined by the CEI Committee. Awards may be granted singly or in combination. Awards to participants may also be made in combination with, in replacement of, or as alternatives to, grants or rights under the plans or any other employee benefit plan of the company. All or part of an Award may be subject to conditions established by the CEI Committee, including continuous service with the company.

- *Stock Options.* Stock options are rights to purchase a specified number of shares of common stock at a specified price. An option granted pursuant to the applicable plan may consist of either an incentive stock option that complies with the requirements of section 422 of the Code, or a nonqualified stock option that does not comply with such requirements. Only employees may receive incentive stock options and such options must have an exercise price per share that is not less than 100% of the fair market value of the common stock underlying the option on the date of grant. Nonqualified stock options also must have an exercise price per share that is not less than the fair market value of the common stock underlying the option on the date of grant. The exercise price of an option must be paid in full at the time an option is exercised.

- *Stock Awards*. Stock awards are Awards of shares of common stock of Crosstex Energy, Inc. or units denominated in common stock, including an Award of restricted stock or restricted stock units. The CEI Committee will determine the terms, conditions and limitations applicable to any stock awards. Rights to dividends or dividend equivalents may be extended to and made part of any stock award at the discretion of the CEI Committee. Stock awards will have a vesting period established in the sole discretion of the CEI Committee, provided that the CEI Committee may provide for earlier vesting by reason of death, disability, retirement or otherwise.

- *Cash Awards*. Cash awards are Awards denominated and payable in cash. The CEI Committee will determine the terms, conditions and limitations applicable to any cash awards.

- *Performance Awards*. At the discretion of the CEI Committee, any of the above-described Awards may be made in the form of a performance award. A performance award is an Award that is subject to the attainment of one or more performance goals. Performance goals need not be based upon an increase or positive result under a particular business criterion and could include, for example, maintaining the status quo or limiting economic losses. The terms, conditions and limitations applicable to any performance award will be decided by the CEI Committee. The Crosstex Energy, Inc. long-term incentive plans do not provide for any right to receive dividend payments or dividend equivalent payments with respect to performance awards during periods occurring prior to the vesting of such performance award. As of January 1, 2014, no performance awards granted remain outstanding.

The CEI Committee may amend, modify, suspend or terminate the long-term incentive plans, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring stockholder approval under any applicable legal requirements will be effective until such approval has been obtained. No incentive stock options may be granted after the tenth anniversary of the effective date of the plan.

In the event of any corporate transaction such as a merger, consolidation, reorganization, recapitalization, separation, stock dividend, stock split, reverse stock split, split up, spin-off or other distribution of stock or property of Crosstex Energy, Inc., the CEI Committee shall substitute or adjust, as applicable: (i) the number of shares of common stock reserved under the plans and the number of shares of common stock available for issuance pursuant to specific types of Awards as described in the plans, (ii) the number of shares of common stock covered by outstanding Awards, (iii) the grant price or other price in respect of such Awards and (iv) the appropriate fair market value and other price determinations for such Awards, in order to reflect such transactions, provided that such adjustments shall only be such that are necessary to maintain the proportionate interest of the holders of Awards and preserve, without increasing, the value of such Awards.

The total value of the equity compensation granted to our executive officers generally has been awarded 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2013, Crosstex Energy, Inc. granted 64,292, 31,055, 31,196, 50,437 and 20,072 restricted shares to Barry E. Davis, William W. Davis, Joe A. Davis, Michael J. Garberding and Stan Golemon, respectively. All performance and restricted shares that we grant are charged against earnings according to FASB ASC 718.

Retirement and Health Benefits. Crosstex Energy GP, LLC offers a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are generally eligible for the same programs on the same basis as other employees of Crosstex Energy GP, LLC. Crosstex Energy GP, LLC maintains a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax deferred basis. In 2013, Crosstex Energy GP, LLC matched 100% of every dollar contributed for contributions of up to 6% of salary (not to exceed the maximum amount permitted by law) made by eligible participants. The retirement benefits provided to the named executive officers were allocated to us as general and administration expenses. Our executive officers are also eligible to participate in any additional retirement and health benefits available to our other employees.

Perquisites. Crosstex Energy GP, LLC generally does not pay for perquisites for any of the named executive officers, other than payment of dues, sales tax and related expenses for membership in an industry-related private lunch club (totaling less than $2,500 per year per person).

Employment and Severance Agreements

All of our named executive officers and certain members of senior management entered into employment agreements with Crosstex Energy GP, LLC as of February 28, 2012. These employment agreements are substantially similar with certain exceptions which are set forth in the following discussion. The term of the agreement for Barry E. Davis is three years, expiring on February 28, 2015. The initial term of the employment agreements for William W. Davis, Joe A. Davis and Michael J. Garberding was two years, but pursuant to amendments entered into on February 25, 2014, the terms of the foregoing agreements were extended until August 31, 2014. The term of the employment agreements for other members of senior management (including Stan Golemon) is one year with automatic extensions such that the remaining term of the agreements will not be less than one year. The employment agreements restrict such employees from disclosing confidential information, soliciting other employees to accept employment with a third party or terminate their employment with our general partner or its affiliates or competing with our general partner and its affiliates, in each case for a period that will continue after the termination of the employee's employment for one year for Barry E. Davis and for six months for the other executive officers and members of senior management. During the noncompetition period, the employees are generally prohibited from engaging in any business that competes with us or our affiliates in areas in which we conduct business as of the date of termination and from soliciting or inducing any of our employees to terminate their employment with us. The employment agreements provide a clawback of benefits if the confidential information or noncompetition provisions are breached by a terminated employee following a termination date. In the event of a termination, the terminated employee is required to execute a general release of us in order to receive any benefits under the employment agreements.

Under the employment agreements, employees receive their annual base salary and are eligible to participate in cash and equity incentive bonus programs based on criteria established by the Board. If an employee's employment is terminated without cause (as defined in the employment agreement), or is terminated by the employee for good reason (as defined in the employment agreement), or is terminated due to the employee's death, disability or adjudication of legal incompetence, the employment agreement provides that the employee will be entitled to receive (i) his or her base salary up to the date of termination, (ii) any unpaid annual bonus with respect to the prior year that has been earned as of or prior to the date of termination (iii) a pro-rata portion of the higher of (x) the target amount of his or her annual bonus and (y) the projected annual bonus, in each case calculated based upon the number of days in the performance period prior up to the date of termination, (iv) an amount equal to the cost to the employee for the premium for health insurance continuation under COBRA for an 18-month period, (v) such other fringe benefits (excluding any bonus, severance pay benefit, participation in the company's 401(k) employee benefit plan, or medical insurance benefit) normally provided to employees of the company and already earned or accrued as of the date of termination (collectively, the "Termination Fee") and (vi) a lump sum severance amount equal to one year of the employee's then current base salary, plus one times the target annual bonus for the year of termination (the amount listed in (vi) the "Severance Benefit); provided, however, that the Severance Benefit for the Chief Executive Officer is multiplied by two.

Potential Payments Upon Termination and a Change of Control.

As described above, the employment agreements for our named executive officers and certain members of senior management provide for payment to be made to them under certain circumstances upon the termination of their employment. In connection with determining the type, amount and timing of the payment to be made upon the termination of employment under the employment agreements, the Committee reviewed available market information and identified those payments and provision that the Committee deemed to be appropriate for inclusion in the employment agreements. In the event of an executive officer's termination without cause, or a termination by the employee for good reason, within 120 days prior to or one year following a change of control (as defined in the employment agreements), Barry E. Davis would be entitled to receive the Termination Fee plus a lump sum severance amount equal to three times the Severance Benefit, and William W. Davis, Joe A. Davis and Michael J. Garberding each would be entitled to receive the Termination Fee plus a lump sum severance amount equal to two times the Severance Benefit. Other members of senior management (including Stan Golemon) do not receive an increase in the Severance Benefit if they are terminated in connection with a change of control.

If the payments and benefits provided to an executive officer (i) constitute a "parachute payment" as defined in Section 280G of the Internal Revenue Code and exceed three times executive officer's "base amount" as defined under Internal Revenue Code Section 280G(b)(3), and (ii) would be subject to the excise tax imposed by Internal Revenue Code Section 4999, then the executive officer's payments and benefits shall be either (A) paid in full, or (B) reduced and payable only as to the maximum amount which would result in no portion of such payments and benefits being subject to excise tax under Internal Revenue Code Section 4999, whichever results in the receipt by the executive officer on an after-tax basis of the greatest amount (taking into account the applicable federal, state and local income taxes, the excise tax imposed by Internal Revenue Code Section 4999 and all other taxes, including any interest and penalties, payable by the executive officer).

With respect to the long-term incentive plans, the amounts to be received by our named executive officers in the event of a change in control (as defined in the long-term incentive plans) will be automatically determined based on the number of units or shares of common stock underlying any unvested equity incentive awards held by a named executive officer at the time of a change in control. The terms of the long-term incentive plans were determined based on past practice and the applicable compensation committee's understanding of similar plans utilized by public companies generally at the time we adopted such plans. The determination of the reasonable consequences of a change of control is periodically reviewed by the applicable compensation committee.

Upon a change in control, all granted awards will automatically vest and become payable or exercisable, as the case may be, in full, and any performance criteria may, subject to the award, terminate or be deemed to have been achieved at the maximum level. The consummation of the Mergers and Contribution will constitute a change in control of the Partnership, our general partner and CEI under the applicable long-term incentive plans (the "Devon Change in Control").

Notwithstanding the foregoing, in connection with the Merger Agreement and the Contribution Agreement, Barry E. Davis, Michael J. Garberding and Joe A. Davis each agreed to waive certain rights with respect to the acceleration and vesting of awards in connection with the Devon Change in Control. As a result of such waiver, the applicable awards will not become payable or vest solely as a result of the Devon Change in Control unless a qualifying termination occurs on or after the Closing. Such awards granted in or with respect to shares of CEI common stock will be converted from awards in respect of shares of CEI common stock to awards in respect of EnLink Midstream common units. Awards granted in or with respect to the Partnership's common units will be unchanged following the Devon Change in Control. As consideration for such waivers, our Board and the CEI Board, upon the recommendation of their respective compensation committees, approved and authorized the Partnership and CEI to fund a cash bonus pool in an aggregate amount of approximately $600,000 to provide cash awards to these individuals. In February 2014, the compensation committees awarded $251,058 to Barry E. Davis pursuant to this cash bonus pool, and the compensation committees, the Board and the CEI Board approved allocations of $110,778 and $190,928 to Joe A. Davis and Michael J. Garberding, respectively, pursuant to this cash bonus pool. Such cash bonus awards are contingent upon the Closing.

Additionally, certain other of our employees, including Stan Golemon (each, an "Electing Employee"), have agreed to waive their right to accelerated vesting with respect to 50% of their currently unvested equity awards (the "Waiver Awards") granted under the Plan and the CEI long-term incentive plan. Each Electing Employee's Waiver Awards will be amended, effective immediately prior to the Closing to provide that such awards will not vest at such time but will vest on the second anniversary of the Closing. Upon vesting, the Waiver Awards will entitle the Electing Employee to (i) the number of Partnership common units equal to the number of Partnership common units subject to such Waiver Awards and/or (ii) the number of EnLink Midstream common units equal to the number of shares of CEI's common stock subject to the Waiver Awards, as applicable. The remaining 50% of the unvested equity awards in the Partnership and CEI held by each Electing Employee will vest in accordance with the terms of the applicable benefit plan as described above.

As consideration for agreeing to waive the right to accelerated vesting with respect to the Waiver Awards, each Electing Employee will receive (i) a new restricted incentive units award under the Plan for a number of Partnership common units equal to 50% of the Partnership common units subject to the applicable Waiver Awards (rounded up, as necessary, to the nearest whole number of Partnership common units) and (ii) a new restricted incentive units award under the EnLink Midstream, LLC 2014 Long-Term Incentive Plan, which was adopted by the board of directors of the manager of EnLink Midstream and approved by the unitholder of EnLink Midstream in February 2014, for a number of EnLink Midstream common units equal to (1) 50% of the shares of CEI common stock subject to the applicable Waiver Awards plus (2) an amount of EnLink Midstream common units to be determined by dividing (x) the product of the per share cash consideration to be paid to CEI's stockholders pursuant to the Mergers (which consideration will be equal to $100,000,000 divided by the number of shares of common stock issued and outstanding immediately prior to the Closing) and the number of shares of common stock subject to the applicable Waiver Awards by (y) the closing price of the EnLink Midstream common units on the first day of trading following the Closing (in each case rounded up, as necessary, to the nearest whole number of EnLink Midstream common units) (collectively, the "New Awards"). The New Awards will be awarded following the Closing and will vest on the second anniversary of the Closing (unless a qualifying termination (as defined in the applicable award agreement) occurs during such two-year period).

The proposal regarding the Waiver Awards was made pursuant to the terms of the Merger Agreement and the Contribution Agreement and was authorized by our Board and the CEI Board, upon the recommendation of their respective compensation committees.

The potential payments that may be made to the named executive officers upon a termination of their employment or in connection with a change of control as of December 31, 2013 are set forth in the table in the section below entitled Payments Upon Termination or Change in Control.

Role of Executive Officers in Executive Compensation.

The Board, upon recommendation of the Committee, determines the compensation payable to each of the named executive officers. None of the named executive officers serves as a member of the Committee. Barry E. Davis, the Chief Executive Officer, reviews his recommendations regarding the compensation of his leadership team with the Committee, including specific recommendations for each element of compensation for the named executive officers. Barry E. Davis does not make any recommendations regarding his personal compensation.

Tax and Accounting Considerations.

Our equity compensation grant policies have been impacted by the implementation of FASB ASC 718, which we adopted effective January 1, 2006. Under this accounting pronouncement, we are required to value unvested unit options granted prior to our adoption of FASB ASC 718 under the fair value method and expense those amounts in the income statement over the stock option's remaining vesting period. As a result, we currently intend to discontinue grants of unit option and stock option awards and instead grant restricted unit and restricted stock awards to the named executive officers and other employees. We have structured the compensation program to comply with Internal Revenue Code Section 409A. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income. In 2013, none of the named executive officers or other employees had non-performance based compensation paid in excess of the $1.0 million tax deduction limit contained in Internal Revenue Code Section 162(m).

Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Stock Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)		Total ($)
Barry E. Davis	2013	525,000	492,188	1,609,522	—	—	—	266,774	(3)	2,893,484
President and Chief Executive	2012	500,000	406,250	1,333,787	—	—	—	257,496		2,497,533
Officer	2011	460,000	545,882	1,418,773	—	—	—	195,958		2,620,613
William W. Davis	2013	395,000	266,625	751,112	—	—	—	165,039	(4)	1,577,776
Executive Vice President and	2012	385,000	225,225	800,272	—	—	—	185,462		1,595,959
Chief Operating Officer	2011	352,692	376,675	917,837	—	—	—	151,644		1,798,848
Joe A. Davis	2013	350,000	236,250	751,112	—	—	—	134,082	(5)	1,471,444
Executive Vice President and	2012	335,000	163,313	640,212	—	—	—	156,960		1,295,485
General Counsel	2011	315,000	242,992	620,948	—	—	—	145,004		1,323,944
Michael J. Garberding	2013	350,000	224,100	1,465,519	—	—	—	164,596	(6)	2,204,215
Executive Vice President and	2012	290,000	141,375	640,212	—	—	—	138,874		1,210,461
Chief Financial Officer	2011	256,538	197,894	848,713	—	—	—	88,124		1,391,269
Stan Golemon	2013	285,000	128,250	536,512	—	—	—	102,847	(7)	1,052,609
Senior Vice President	2012	275,000	89,375	533,515	—	—	—	99,281		997,171
	2011	249,615	124,808	445,253	—	—	—	80,363		900,039

(1) Bonuses include all payments made under the Annual Bonus Plan. For 2013 and 2012, the named executive officers received bonuses in the form of stock awards that immediately vest. The amounts shown for 2013 and 2012 represent the grant date fair value of awards computed in accordance with FASB ASC 718. Such awards were allocated 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. See "Bonus Awards" above.

(2) The amounts shown represent the grant date fair value of awards computed in accordance with FASB ASC 718. See Note 9 to our audited financial statements included in Item 8 herein for the assumptions made in our valuation of such awards.

(3) Amount of all other compensation for Mr. Barry Davis includes professional organization and social club dues, a matching 401(k) contribution of $18,368, distributions on restricted incentive units and performance units of Crosstex Energy, L.P. in the amount $165,216 in 2013, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $80,673 in 2013.

(4) Amount of all other compensation for Mr. William Davis includes professional organization and social club dues, a matching 401(k) contribution of $20,658, distributions on restricted incentive units and performance units of Crosstex Energy, L.P. in the amount of $94,726 in 2013 and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $47,138 in 2013.

(5) Amount of all other compensation for Mr. Joe Davis includes professional organization and social club dues, a matching 401(k) contribution of $17,900, distributions on restricted incentive units and performance units of Crosstex Energy, L.P. in the amount of $76,388 in 2013, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $37,278 in 2013.

(6) Amount of all other compensation for Mr. Michael Garberding includes professional organization and social club dues, a matching 401(k) contribution of $17,500, distributions on restricted incentive units of Crosstex Energy, L.P. in the amount of $97,843 in 2013, and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $46,737 in 2013.

(7) Amount of all other compensation for Mr. Stan Golemon includes a matching 401(k) contribution of $15,782, distributions on restricted incentive units of Crosstex Energy, L.P. in the amount of $56,970 in 2013, and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $27,578 in 2013.

Grants of Plan-Based Awards for Fiscal Year 2013 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2013, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plans.

CROSSTEX ENERGY GP, LLC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Number of Units		Grant Date Fair Value of Unit Awards
Barry E. Davis	1/15/2013	51,546	(1)	$ 806,179
	3/4/2013	11,567	(2)	$ 203,117
William W. Davis	1/15/2013	24,055	(1)	$ 376,220
	3/4/2013	6,413	(2)	$ 112,612
Joe A. Davis	1/15/2013	24,055	(1)	$ 376,220
	3/4/2013	6,549	(2)	$ 115,000
Michael J. Garberding	1/15/2013	30,928	(1)	$ 483,714
	3/4/2013	6,549	(2)	$ 115,000
	8/7/2013	11,985	(3)	$ 253,962
Stan Golemon	1/15/2013	17,182	(1)	$ 268,726
	3/4/2013	2,545	(2)	$ 44,690

(1) These grants include Distribution Equivalent Rights (DERs) that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2016.

(2) These grants vested on March 8, 2013.

(3) These grants include Distribution Equivalent Rights (DERs) that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on July 31, 2016.

CROSSTEX ENERGY, INC.—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Number of Shares		Grant Date Fair Value of Shares Awards
Barry E. Davis	1/15/2013	52,301	(1)	$ 803,343
	3/4/2013	11,991	(2)	$ 203,128
William W. Davis	1/15/2013	24,407	(1)	$ 374,892
	3/4/2013	6,648	(2)	$ 112,617
Joe A. Davis	1/15/2013	24,407	(1)	$ 374,892
	3/4/2013	6,789	(2)	$ 115,006
Michael J. Garberding	1/15/2013	31,381	(1)	$ 482,012
	3/4/2013	6,789	(2)	$ 115,006
	8/7/2013	12,267	(3)	$ 245,831
Stan Golemon	1/15/2013	17,434	(1)	$ 267,786
	3/4/2013	2,638	(2)	$ 44,688

(1) These grants include right to receive dividends on restricted shares if made on unrestricted common shares during the restricted period unless otherwise forfeited and vest 100% on January 1, 2016.

(2) These grants vested on March 8, 2013.

(3) These grants include right to receive dividends on restricted shares if made on unrestricted common shares during the restricted period unless otherwise forfeited and vest 100% on July 31, 2016.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2013

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2013, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plans.

CROSSTEX ENERGY GP, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards					Stock Awards				
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Units That Have Not Vested (#)		Market Value of Units That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Barry E. Davis	—	—	—	—	—	31,944	(1)	881,654	—	—
						15,272	(3)	421,507		
						38,250	(4)	1,055,700		
						51,546	(5)	1,422,670		
William W. Davis	—	—	—	—	—	17,969	(1)	495,944	—	—
						12,217	(3)	337,189		
						22,950	(4)	633,420		
						24,055	(5)	663,918		
Joe A. Davis	—	—	—	—	—	16,406	(1)	452,806	—	—
						4,582	(3)	126,463		
						18,360	(4)	506,736		
						24,055	(5)	663,918		
Michael J. Garberding	—	—	—	—	—	8,507	(1)	234,793	—	—
						18,326	(3)	505,798		
						18,360	(4)	506,736		
						30,928	(5)	853,613		
						11,985	(6)	330,786		
Stan Golemon	—	—	—	—	—	8,507	(1)	234,793	—	—
						6,109	(3)	168,608		
						15,300	(4)	422,280		
						17,182	(5)	474,223		

(1) Restricted incentive units vested on January 1, 2014.

(2) The closing price for the common units was $27.60 as of December 31, 2013.

(3) Restricted incentive units vest on August 15, 2014.

(4) Restricted incentive units vest on January 1, 2015.

(5) Restricted incentive units vest on January 1, 2016.

(6) Restricted incentive units vest on July 31, 2016.

CROSSTEX ENERGY, INC.—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards					Stock Awards				
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units That Have Not Vested (#)		Market Value of Shares or Units That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Barry E. Davis	—	—	—	—	—	51,919	(1)	1,877,391	—	—
						23,148	(3)	837,032		
						50,080	(4)	1,810,893		
						52,301	(5)	1,891,204		
William W. Davis	—	—	—	—	—	29,204	(1)	1,056,017	—	—
						18,519	(3)	669,647		
						30,048	(4)	1,086,536		
						24,407	(5)	882,557		
Joe A. Davis	—	—	—	—	—	26,665	(1)	964,206		
						6,944	(3)	251,095		
						24,038	(4)	869,214		
						24,407	(5)	882,557		
Michael J. Garberding	—	—	—	—	—	13,826	(1)	499,948	—	—
						27,778	(3)	1,004,452		
						24,038	(4)	869,214		
						31,381	(5)	1,134,737		
						12,267	(6)	443,575		
Stan Golemon	—	—	—	—	—	13,826	(1)	499,948	—	—
						9,259	(3)	334,805		
						20,032	(4)	724,357		
						17,434	(5)	630,413		

(1) Restricted shares vested on January 1, 2014.

(2) The closing price for the common shares was $36.16 as of December 31, 2013.

(3) Restricted shares vest on August 15, 2014.

(4) Restricted shares vest on January 1, 2015.

(5) Restricted shares vest on January 1, 2016.

(6) Restricted shares vest on July 31, 2016.

Units and Shares Vested Table for Fiscal Year 2013

The following table provides information related to the vesting of restricted incentive units and restricted shares during fiscal year ended 2013.

UNITS AND SHARES VESTED

	Crosstex Energy, L.P. Unit Awards			Crosstex Energy, Inc. Share Awards		
Name	Number of Units Acquired on Vesting	Value Realized on Vesting		Number of Shares Acquired on Vesting	Value Realized on Vesting	
Barry E. Davis	46,290	$ 711,684	(1)	46,714	$ 711,248	(2)
William W. Davis	36,970	$ 559,070	(3)	37,205	$ 556,455	(4)
Joe A. Davis	37,106	$ 561,498	(5)	37,346	$ 558,964	(6)
Michael J. Garberding	20,414	$ 343,858	(7)	22,205	$ 373,836	(8)
Stan Golemon	16,434	$ 247,510	(9)	16,527	$ 246,098	(10)

(1) Consists of 34,723 units at $14.55 per unit and 11,567 units at $17.85 per unit.

(2) Consists of 34,723 shares at $14.34 per share and 11,991 shares at $17.79 per share.

(3) Consists of 30,557 units at $14.55 per unit and 6,413 units at $17.85 per unit.

(4) Consists of 30,557 shares at $14.34 per share and 6,648 shares at $17.79 per share.

(5) Consists of 30,557 units at $14.55 per unit and 6,549 units at $17.85 per unit.

(6) Consists of 30,557 shares at $14.34 per share and 6,789 shares at $17.79 per share.

(7) Consists of 9,723 units at $14.55 per unit, 4,142 units at $20.64 per unit and 6,549 units at $17.85 per unit.

(8) Consists of 9,723 shares at $14.34 per share, 5,693 shares at $19.96 per share and 6,789 shares at $17.79 per share.

(9) Consists of 13,889 units at $14.55 per unit and 2,545 units at $17.85 per unit.

(10) Consists of 13,889 shares at $14.34 per share and 2,638 at $17.79 per share.

Payments Upon Termination or Change of Control

The following tables show potential payments that would have been made to the named executive officers as of December 31, 2013.

Name and Principal Position	Payment Under Employment Agreements Upon Termination Other Than For Cause or With Good Reason ($)(1)	Health Care Benefits Under Employment Agreements Upon Termination Other Than For Cause or With Good Reason ($)(2)	Payment and Health Care Benefits Under Employment Agreements Upon Termination For Cause or Without Good Reason ($)(3)	Payment Under Employment Agreements Upon Termination and Change of Control ($)(4)	Acceleration of Vesting Under Long-Term Incentive Plans Upon Change of Control ($)(5)
Barry E. Davis *President and Chief Executive Officer*	3,047,741	28,991	—	4,228,991	10,198,051
William W. Davis *Executive Vice President and Chief Operating Officer*	1,125,676	19,676	—	1,876,176	5,825,228
Joe A. Davis *Executive Vice President and General Counsel*	1,008,991	28,991	—	1,673,991	4,716,995
Michael J. Garberding *Executive Vice President and Chief Financial Officer*	1,008,991	28,991	—	1,673,991	6,383,652
Stan Golemon *Senior Vice President*	646,264	19,264	—	646,264	3,489,429

(1) Each named executive officer is entitled to the Termination Fee plus a lump sum amount equal to one times (two times in the case of the Chief Executive Officer) his then current base salary plus one times (two times in the case of the Chief Executive Officer) the target annual bonus for the year of termination if he is terminated without cause or due to death or disability, or if he terminates employment for good reason (as defined in the employment agreement), subject to compliance with certain non-competition and non-solicitation covenants described elsewhere in this Annual Report on Form 10-K. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(2) Each named executive officer is entitled to health care benefits equal to a lump sum payment of the estimated monthly cost of the benefits under COBRA for 18 months if he is terminated without cause or due to death or disability, or if he terminates employment for good reason.

(3) Each named executive officer is entitled to his then current base salary up to the date of termination plus such other fringe benefits (other than any bonus, severance pay benefit, participation in the company's 401(k) employee benefit plan, or medical insurance benefit) normally provided to employees of the company as earned up to the date of termination if he is terminated for cause (as defined in the employment agreement) or he terminates employment without good reason. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(4) Each named executive officer (except Mr. Golemon) is entitled to the Termination Fee plus a lump sum payment equal to two times (three times in the case of the Chief Executive Officer) his then current base salary plus two times (three times in the case of the Chief Executive Officer) the target annual bonus for the year of termination if he is terminated without cause or if he terminates employment for good reason within one-hundred and twenty (120) days prior to or one (1) year following a change in control (as defined in the employment agreement), subject to compliance with certain non-competition and non-solicitation covenants described elsewhere in this Annual Report on Form 10-K. A change in control

event does not impact the payment to which Mr. Golemon would otherwise be entitled. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(5) Each named executive officer is entitled to accelerated vesting of outstanding equity awards in the event of a change in control (as defined under the long term incentive plans). These amounts correspond to the values set forth in the table in the section above entitled Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2013.

Compensation of Directors for Fiscal Year 2013

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards(1) ($)	All Other Compensation(2) ($)	Total ($)
Rhys J. Best	192,500	100,003	7,385	299,888
Leldon E. Echols	124,750	75,005	3,933	203,688
Bryan H. Lawrence	—	—	—	—
Cecil E. Martin	106,542	75,005	3,933	185,480
Kyle D. Vann	159,000	74,997	5,539	239,536
D. Dwight Scott	158,003	—	—	158,003

(1) Messrs. Best, Echols. Martin and Vann were granted awards of restricted incentive units of Crosstex Energy, L.P. on May 9, 2013 with a fair market value of $19.03 per unit and that will vest on May 9, 2014 in the following amounts, respectively: 5,255, 1,971, 1,971 and 3,941. Messrs. Echols and Martin were granted awards of restricted shares of Crosstex Energy, Inc. on May 9, 2013 with a fair market value of $18.30 per share and that will vest on May 9, 2014 in the following amounts, respectively: 2,049 and 2,049. The amounts shown represent the grant date fair value of awards computed in accordance with FASB ACS 718. See Note 9 to our audited financial statements included in Item 8 herein for the assumptions made in our valuation of such awards. At December 31, 2013, Messrs. Best, Echols, Martin and Vann held aggregate outstanding restricted incentive unit awards, in the following amounts, respectively: 5,255, 1,971, 1971 and 3,941. At December 31, 2013, Messrs. Echols and Martin held aggregate outstanding restricted shares of Crosstex Energy, Inc. in the following amounts, respectively: 2,049 and 2,049. Messrs. Lawrence and Scott held no outstanding restricted incentive unit awards at December 31, 2013.

(2) Other Compensation is comprised of distributions on restricted incentive units and dividends received on restricted shares.

Each director of Crosstex Energy GP, LLC who is not an employee of Crosstex Energy GP, LLC (other than Mr. Lawrence) is paid an annual retainer fee of $50,000, except for Mr. Best who, as Chairman, is paid an annual retainer fee of $50,000 and Mr. Scott who receives an annual retainer fee of $125,000 (and does not receive any equity related compensation). Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting but are paid $1,500 for each additional meeting that they attend. Also, an attendance fee of $1,500 is paid to each director for each committee meeting that is attended, other than the Audit Committee which pays a fee of $3,000 per meeting. The respective Chairs of each committee receive the following annual fees: Audit—$12,000, Compensation—$10,000, Governance—$10,000, Finance—$5,000 and Conflicts—$2,500. Directors are also reimbursed for related out-of-pocket expenses. Barry E. Davis, as an executive officer of Crosstex Energy GP, LLC, is otherwise compensated for his services and therefore receives no separate compensation for his service as a director. For directors that serve on both the boards of Crosstex Energy GP, LLC and Crosstex Energy, Inc., the above listed fees are generally allocated 75% to us and 25% to Crosstex Energy, Inc., except in the case for service on the Audit Committee, where the Chair is paid a separate fee for each entity and meeting fees are split 50% to each entity. The Governance Committee annually reviews and makes recommendations to the Board regarding the compensation of the directors. Mr. Lawrence received no compensation in 2013. See related party transactions for a discussion of compensation for Mr. Scott.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended 2013, the Committee was composed of Cecil E. Martin, Rhys J. Best and D. Dwight Scott. No member of the Committee during fiscal 2013 was a current or former officer or employee of Crosstex Energy GP, LLC or had any relationship requiring disclosure by us under Item 404 of Regulation S-K as adopted by the SEC. None of Crosstex Energy GP, LLC's executive officers served on the board of directors or the compensation committee of any other entity for which any officers of such other entity served either on the Board or the Committee.

The Compensation Committee of Crosstex Energy GP, LLC held five meetings during fiscal year 2013. Each member attended 100% of the meetings.

Board Leadership Structure and Risk Oversight

The Board has no policy that requires that the positions of the Chairman of the Board and the Chief Executive Officer be separate or that they be held by the same individual. The Board believes that this determination should be based on circumstances existing from time to time, including the current business environment and any specific challenges facing the business and the composition, skills, and experience of the board and its members. At this time, the positions of Chairman of the Board and the Chief Executive Officer of Crosstex Energy GP, LLC are not held by the same individual. Rhys J. Best serves as the Chairman of the Board and Barry E. Davis serves as the President and Chief Executive Officer. The Board believes this is the most appropriate structure for the Partnership at this time because it makes the best use of Mr. Best's skills and experience, including his prior service as the Chief Executive Officer of a large public company, while enhancing Mr. Davis' ability to lead decisively and communicate our message and strategy clearly and consistently to our unitholders, employees and customers.

The Board is responsible for risk oversight. Management has implemented internal processes to identify and evaluate the risks inherent in the company's business and to assess the mitigation of those risks. The Audit Committee has reviewed the risk assessments with management and provided reports to the Board regarding the internal risk assessment processes, the risks identified, and the mitigation strategies planned or in place to address the risks in the business. The Board and the Audit Committee each provide insight into the issues, based on the experience of their members, and provide constructive challenges to management's assumptions and assertions.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters*

Crosstex Energy, L.P. Ownership

The following table shows the beneficial ownership of units of Crosstex Energy, L.P. as of February 14, 2014, held by:

- each person who beneficially owns 5% or more of any class of units then outstanding;
- all the directors of Crosstex Energy GP, LLC;
- each named executive officer of Crosstex Energy GP, LLC; and
- all the directors and executive officers of Crosstex Energy GP, LLC as a group.

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Percentages reflected in the table are based upon a total of 91,534,187 common units as of February 14, 2014.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Series A Convertible Preferred Units Beneficially Owned	Percentage of Preferred Units Beneficially Owned	Total Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Crosstex Energy, Inc.	16,414,830	17.93%	—	—	16,414,830	15.11%
GSO Crosstex Holdings, LLC(2)	902,162	0.99%	17,095,132	100.00%	17,997,294	16.57%
Kayne Anderson Capital Advisors(3)	7,963,188	8.70%	—	—	7,963,188	7.33%
Clearbridge Investments, LLC	5,800,200	6.34%	—	—	5,800,200	5.34%
OppenheimerFunds, Inc.	7,489,667	8.18%	—	—	7,489,667	6.89%
Oppenheimer StellPath MLP Fund	5,747,331	6.28%			5,747,331	5.29%
Barry E. Davis(4)	366,036	*	—	—	366,036	*
William W. Davis(4)	114,563	*	—	—	114,563	*
Joe A. Davis(4)	50,310	*	—	—	50,310	*
Stan Golemon(4)	32,215	*	—	—	32,215	*
Michael J. Garberding(4)	42,397	*	—	—	42,397	*
Rhys J. Best(5)	107,333	*	—	—	107,333	*
Leldon E. Echols(4)	19,153	*	—	—	19,153	*
Bryan H. Lawrence(4)	—	—	—	—	—	—
Cecil E. Martin(4)	27,563	*	—	—	27,563	*
D. Dwight Scott	—	—	—	—	—	—
Kyle D. Vann	75,304	*	—	—	75,304	*
All directors and executive officers as a group (11 persons)	834,874	0.91%	—	—	834,874	0.77%

* Less than 1%

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for GSO Crosstex Holdings LLC, which is 280 Park Avenue, 11th Floor, New York, NY 10017; Kayne Anderson Capital Advisors, L.P., which is 1800 Avenue of the Stars, Third Floor, Los Angeles, California 90067; and Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022; Clearbridge Investment, LLC, which is 620 8th Avenue, New York Avenue. New York, NY 10018; OpperheimerFunds, Inc, which is 225 liberty street New York, NY 10281; Oppenheimer SteelPath MLP Income Fund, which is 6803 South Tucson Way, Centennial, CO 80112.

(2) As reported on Schedule 13D and Form 4 filed with the SEC in joint filings with Blackstone / GSO Capital Solutions Fund LP, Blackstone / GSO Capital Solutions Associates LLC, Bennett J. Goodman, J. Albert Smith III, Douglas I. Ostrover, GSO Holdings I LLC, Blackstone Holdings I L.P., Blackstone Holdings I/II GP Inc., The Blackstone Group L.P., Blackstone Group Management L.L.C., Stephen A. Schwarzman, GSO Capital Partners LP, GSO Advisor Holdings L.L.C., GSO Special Situation Fund LP, and GSO Special Situations Overseas Master Fund Ltd. Such persons share voting and dispositive power with respect to the units.

(3) As reported on Schedule 13G filed with the SEC in a joint filing with Richard A. Kayne. Such persons report shared voting and dispositive power with respect to the units.

(4) These individuals each hold an ownership interest in Crosstex Energy, Inc. as indicated in the following table.

(5) Of these units, 15,000 are held by the Best Grandchildren's Trust, 30,000 are held by the Anne E. Stone Trust, and 30,000 are held by the Paul Best Trust. The beneficiaries of these trusts are members of Mr. Best's family.

Crosstex Energy, Inc. Ownership

The following table shows the beneficial ownership of Crosstex Energy, Inc. as of February 14, 2014, held by:

- each person who beneficially owns 5% or more of the stock then outstanding;

- all the directors of Crosstex Energy, Inc.;
- each named executive officer of Crosstex Energy, Inc.; and
- all the directors and executive officers of Crosstex Energy, Inc. as a group.

Percentages reflected in the table below are based on a total of 48,021,537 shares of common stock outstanding as of February 14, 2014.

Name of Beneficial Owner(1)	Shares of Common Stock	Percent
GSO Crosstex Holdings, LLC(2)	7,000,000	14.58%
Chickasaw Capital Management, LLC(3)	4,149,252	8.64%
Black Rock Inc.	2,644,471	5.51%
Barry E. Davis (4)	1,722,083	3.59%
William W. Davis (4)	266,633	*
Joe A. Davis (4)	108,843	*
Stan Golemon (4)	46,459	*
Michael J. Garberding (4)	50,302	*
James C. Crain (5)	52,298	*
Leldon E. Echols (4)	22,400	*
Bryan H. Lawrence (4)	1,720,267	3.58%
Cecil E. Martin (4)	12,400	*
Robert F. Murchison (6)	274,150	*
All directors and executive officers as group (10 persons)	4,275,835	8.90%

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for GSO Crosstex Holdings, LLC which is 345 Park Avenue, New York, New York 10154; Chickasaw Capital Management, LLC which is 6075 Poplar Ave., Suite 402 Memphis, TN 38119; Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022; Black Rock Inc., which is 40 East 52nd street, New York, NY 10022.

(2) As reported on Schedule 13D and Form 4 filed with the SEC in joint filings with Blackstone / GSO Capital Solutions Fund LP, Blackstone / GSO Capital Solutions Associates LLC, Bennett J. Goodman, J. Albert Smith III, Douglas I. Ostrover, GSO Holdings I LLC, Blackstone Holdings I L.P., Blackstone Holdings I/II GP Inc., The Blackstone Group L.P., Blackstone Group Management L.L.C., Stephen A. Schwarzman, GSO Capital Partners LP, GSO Advisor Holdings L.L.C., GSO Special Situation Fund LP, and GSO Special Situations Overseas Master Fund Ltd. Such persons shared voting and dispositive power with respect to the shares.

(3) As reported on Schedule 13G filed with the SEC.

(4) These individuals each hold an ownership interest in Crosstex Energy, L.P. as indicated in the table above.

(5) 1,000 of these shares are held by the James C. Crain Trust.

(6) 169,462 shares are held by Murchison Capital Partners, L.P. Mr. Murchison is the President of the Murchison Management Corp., which serves as the general partner of Murchison Capital Partners, L.P.

Beneficial Ownership of General Partner Interest

Crosstex Energy GP, LLC owns all of our general partner interest and all of our incentive distribution rights. Crosstex Energy GP, LLC is 100% owned by Crosstex Energy, Inc.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights		Weighted-Average Price of Outstanding Options, Warrants and Rights		Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column(a))
	(a)		(b)		(c)
Equity Compensation Plans Approved By Security Holders(1)	1,373,037	(2)	$ 8.36	(3)	3,754,195
Equity Compensation Plans Not Approved By Security Holders	N/A		N/A		N/A

(1) Our Amended and Restated Long-Term Incentive Plan was approved by our unitholders in May 2013 for the benefit of our officers, employees and directors. See Item 11, "Executive Compensation—Compensation Discussion and Analysis." The plan, as amended, provides for the issuance of a total of 9,070,000 common units under the plan.

(2) The number of securities includes 1,178,923 restricted incentive units that have been granted under our long-term incentive plan that have not vested.

(3) The exercise prices for outstanding options under the plan as of December 31, 2013 range from $3.11 to $37.31 per unit.

Item 13. ***Certain Relationships and Related Transactions and Director Independence***

Our General Partner

Our operations and activities are managed by, and our officers are employed by, the Operating Partnership. Our general partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf.

Our general partner owns the general partner interest in us and all of our incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit.

Relationship with Crosstex Energy, Inc.

General. Crosstex Energy, Inc. ("CEI"), directly or indirectly, owns 16,414,830 common units, representing an approximate 15.0% limited partnership interest in us as of December 31, 2013. CEI also owns our general partner. Our general partner owns the general partner interest in us and the incentive distribution rights. Our general partner's ability, as general partner, to manage and operate Crosstex Energy, L.P. and CEI's ownership in us effectively gives our general partner the ability to veto some of our actions and to control our management. CEI pays us for administrative and compensation costs that we incur on its behalf. During 2013, this cost reimbursement was approximately $0.08 million per month.

Omnibus Agreement. Concurrently with the closing of our initial public offering, we entered into an agreement with CEI and our general partner that governs potential competition among us and the other parties to the agreement. CEI agreed, for so long as our general partner or any affiliate of CEI is a general partner of our Partnership, not to engage in the business of gathering, transmitting, treating, processing, storing and marketing of natural gas and the transportation, fractionation, storing and marketing of NGLs unless it first offers us the opportunity to engage in this activity or acquire this business, and the Board, with the concurrence of its conflicts committee, elects to cause us not to pursue such opportunity or acquisition. In addition, CEI has the ability to purchase a business that has a competing natural gas gathering, transmitting, treating, processing and producer services business if the competing business does not represent the majority in value of the business to be acquired and CEI offers us the opportunity to purchase the competing operations following their acquisition. Except as provided above, CEI and its controlled affiliates are not prohibited from engaging in activities in which they compete directly with us.

Related Party Transactions

Reimbursement of Costs by CEI. CEI paid us $1.0 million, $0.7 million and $0.8 million during the years ended December 31, 2013, 2012, and 2011, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI. This reimbursement is evaluated on an annual basis. Officers and employees that perform services for CEI provide an estimate of the portion of their time devoted to such services. A portion of their annual compensation (including bonuses, payroll taxes and other benefit costs) is allocated to CEI for reimbursement based on these estimates. In addition, an administrative burden is added to such costs to reimburse us for additional support costs, including, but not limited to, consideration for rent, office support and information service support.

Expense Reimbursement Agreement. In connection with the execution of the Merger Agreement and the Contribution Agreement, we entered into an expense reimbursement agreement with CEI pursuant to which CEI has agreed to reimburse us for our reasonable documented out-of-pocket fees and expenses incurred in connection with the Merger Agreement or the Contribution Agreement, up to a maximum of $2 million, in the event that the Merger Agreement is terminated under circumstances in which CEI is obligated to pay Devon a termination fee. However, CEI will not be required to reimburse us if (i) CEI terminates the merger agreement to enter into a Superior Proposal (as defined in the Merger Agreement) or (ii) the Merger Agreement is otherwise terminated and CEI is obligated to pay the termination fee as a result of entering into an Acquisition Proposal (as defined in the Merger Agreement) within 12 months of such termination, in each case if, prior to or substantially concurrent with CEI's execution of a definitive agreement with respect to any such transaction, we also enter into a transaction involving the acquisition of 40% or more of our consolidated assets or our outstanding common units.

GSO Crosstex Holdings, LLC. GSO Crosstex Holdings, LLC owned 16,642,947 Series A Convertible Preferred Units ("preferred units") and 902,162 common units representing limited partner interests, representing an approximate 16.0% limited partnership interest in us as of December 31, 2013. In addition, GSO Crosstex Holdings, LLC and its affiliates owned 7,000,000 shares of common stock in CEI as of December 31, 2013. In connection with the sale of the preferred units to GSO Crosstex Holdings, LLC, we entered into a Board Representation Agreement by and among our general partner, CEI and GSO Crosstex Holdings, LLC. Pursuant to the Board Representation Agreement, each of the Crosstex entities agreed to take all actions necessary or advisable to cause one director serving on the Board to be designated by GSO Crosstex Holdings, LLC, in its sole discretion. Such designation right will terminate upon the earliest to occur of (i) GSO Crosstex Holdings, LLC and its affiliates holding a number of preferred units and common units issued on conversion of the preferred units that is less than twenty-five percent (25%) of the number of preferred units initially issued to GSO Crosstex Holdings, LLC, (ii) such time as the sum of (A) the number of common units into which the preferred units collectively held by GSO Crosstex Holdings, LLC and its affiliates are convertible and (B) the number of the common units issuable upon conversion of the preferred units which are then collectively held by GSO Crosstex Holdings, LLC and its affiliates represent less than ten percent (10%) of the common units then outstanding and (iii) GSO Crosstex Holdings, LLC ceasing to be an affiliate of The Blackstone Group L.P. GSO Crosstex Holdings, LLC has selected D. Dwight Scott to serve as a director. GSO Crosstex Holdings, LLC (or its affiliates) requires that any compensation due to Mr. Scott be paid directly to GSO Crosstex Holdings, LLC (or its designee). As a result, we will pay GSO Crosstex Holdings, LLC (or its designee) all cash compensation (and the cash value at the date of grant of any equity compensation) otherwise payable to Mr. Scott for his service as a director in accordance with our director compensation policies in place from time to time.

Approval and Review of Related Party Transactions. If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the Board or our senior management, as appropriate. If the Board is involved in the approval process, it determines whether it is advisable to refer the matter to the Conflicts Committee, as constituted under the limited partnership agreement of Crosstex Energy, L.P. The Conflicts Committee operates pursuant to its written charter and our partnership agreement. If a matter is referred to the Conflicts Committee, the Conflicts Committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Director Independence

See "Item 10. Directors, Executive Officers and Corporate Governance" for information regarding director independence.

Item 14. ***Principal Accounting Fees and Services***

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for each of the fiscal years ended December 31, 2013, 2012 and 2011, review of our internal control procedures for the fiscal year ended December 31, 2013, 2012 and 2011 and the reviews of the financial statements included in our Quarterly Reports on Form 10-Q or services that are normally provided by KPMG in connection with statutory or regulatory filings or engagements for each of those fiscal years was $1.4 million, $1.2 million, and $1.1 million, respectively. These amounts also included fees associated with comfort letters and consents related to debt and equity offerings.

Audit-Related Fees

KPMG did not perform any assurance and related services related to the performance of the audit or review of our financial statements for the fiscal years ended December 31, 2013, 2012 and 2011, that were not included in the audit fees listed above.

Tax Fees

KPMG did not perform any tax related services for the years ended December 31, 2013, 2012 and 2011.

All Other Fees

KPMG did not render services to us, other than those services covered in the section captioned "Audit Fees" for the fiscal years ended December 31, 2013, 2012 and 2011.

Audit Committee Approval of Audit and Non-Audit Services

All audit and non-audit services and any services that exceed the annual limits set forth in our annual engagement letter for audit services must be pre-approved by the Audit Committee. In 2014, the Audit Committee has not pre-approved the use of KPMG for any non-audit related services. The Chairman of the Audit Committee is authorized by the Audit Committee to pre-approve additional KPMG audit and non-audit services between Audit Committee meetings; provided that the additional services do not affect KPMG's independence under applicable Securities and Exchange Commission rules and any such pre-approval is reported to the Audit Committee at its next meeting.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) Financial Statements and Schedules

1. See the Index to Financial Statements on page F-1.

2. Exhibits

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number			Description
2.1	**	—	Stock Purchase and Sale Agreement, dated as of May 7, 2012, by and among Energy Equity Partners, L.P., the Individual Owners (as defined therein), Clearfield Energy, Inc., Clearfield Holdings, Inc., West Virginia Oil Gathering Corporation, Appalachian Oil Purchasers, Inc., Kentucky Oil Gathering Corporation, Ohio Oil Gathering Corporation II, Ohio Oil Gathering Corporation III, OOGC Disposal Company I, M&B Gas Services, Inc., Clearfield Ohio Holdings, Inc., Pike Natural Gas Company, Eastern Natural Gas Company, Southeastern Natural Gas Company and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated May 7, 2012, filed with the Commission on May 8, 2012, file No. 000-50067).
2.2	**	—	Contribution Agreement, dated as of October 21, 2013, by and among Devon Energy Corporation, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc., Crosstex Energy, L.P. and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K, dated October 21, 2013, filed with the Commission on October 22, 2013, file No. 000-50067).
3.1		—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2		—	Certificate of Amendment to the Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
3.3		—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007, file No. 000-50067).
3.4		—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007, file No. 000-50067).
3.5		—	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008, file No. 000-50067).
3.6		—	Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
3.7		—	Amendment No. 4 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of September 13, 2012 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated September 13, 2012, filed with the Commission on September 14, 2012, file No. 000-50067).
3.8	*	—	Amendment No. 5 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of February 27, 2014.
3.9		—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.10		—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).

3.11	—	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of January 19, 2010 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.7 to Amendment No. 1 to our Registration Statement on Form S-3, file No. 333-128282).
4.2	—	Indenture, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
4.3	—	Supplemental Indenture, dated as of July 11, 2011, to the Indenture governing the Issuers' 8.875% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors names therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated July 11, 2011, filed with the Commission on July 12, 2011, file No. 000-50067).
4.4	—	Supplemental Indenture, dated as of January 24, 2012, to the Indenture governing the Issuers' 8.875% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Well Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 24, 2012, filed with the Commission on January 25, 2012, file No. 000-50067).
4.5	—	Registration Rights Agreement, dated as of January 19, 2010, by and among Crosstex Energy, L.P. and GSO Crosstex Holdings LLC (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
4.6	—	Indenture governing the Issuers' 71/8% senior unsecured notes due 2022, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated May 23, 2012, filed with the Commission on May 24, 2012, file No. 000-50067).
4.7	—	Registration Rights Agreement, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated May 23, 2012, filed with the Commission on May 24, 2012, file No. 000-50067).
4.8	—	Supplemental Indenture, dated as of August 6, 2012, to the indenture governing the Issuers' 87/8% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
4.9	—	Supplemental Indenture, dated as of August 6, 2012, to the indenture governing the Issuers' 71/8% senior unsecured notes due 2022, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
4.10	—	Supplemental Indenture, dated as of October 5, 2012, to the indenture governing the Issuers' 87/8% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated October 2, 2012, filed with the Commission on October 5, 2012, file No. 000-50067).
4.11	—	Supplemental Indenture, dated as of October 5, 2012, to the indenture governing the Issuers' 71/8% senior unsecured notes due 2022, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated October 2, 2012, filed with the Commission on October 5, 2012, file No. 000-50067).

10.1	†	—	Crosstex Energy, Inc. Amended and Restated Long-Term Incentive Plan effective as of September 6, 2006 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006, file No. 000-50536).
10.2	†	—	Crosstex Energy GP, LLC Amended and Restated Long-Term Incentive Plan, as amended and restated on May 9, 2013 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 9, 2013, filed with the Commission on May 13, 2013, file No. 000-50067).
10.3	†	—	Crosstex Energy, Inc. 2009 Long-Term Incentive Plan, as amended and restated on May 9, 2013 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated May 9, 2013, filed with the Commission on May 13, 2013, file No. 000-50536).
10.4		—	Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.5	†	—	Form of Restricted Unit Agreement (incorporated by reference to Exhibit 10.9 to our Annual Report on Form 10-K for the year ended December 31, 2009, file No. 000-50067).
10.6	†	—	Form of Restricted Incentive Unit Agreement (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated May 9, 2013, filed with the Commission on May 13, 2013, file No. 000-50067).
10.7	†	—	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.9 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2009, file No. 000-50536).
10.8	†	—	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.2 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated May 9, 2013, filed with the Commission on May 13, 2013, file No. 000-50536).
10.9	†	—	Form of Performance Share Agreement (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007, file No. 000-50536).
10.10	†	—	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.11		—	Board Representation Agreement, dated as of January 19, 2010, by and among Crosstex Energy GP, LLC, Crosstex Energy GP, L.P., Crosstex Energy, L.P., Crosstex Energy, Inc. and GSO Crosstex Holdings LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
10.12		—	Amended and Restated Credit Agreement, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer thereunder, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
10.13		—	First Amendment to Amended and Restated Credit Agreement dated as of May 2, 2011, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2011, filed with the Commission on May 3, 2011, file No. 000-50067).
10.14		—	Second Amendment to Amended and Restated Credit Agreement dated as of July 11, 2011, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 11, 2011, filed with the Commission on July 12, 2011, file No. 000-50067).
10.15		—	Third Amendment to Amended and Restated Credit Agreement dated as of January 24, 2012, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 24, 2012, filed with the Commission on January 25, 2012, file No. 000-50067).
10.16		—	Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 23, 2012, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 23, 2012, filed with the Commission on May 24, 2012, file No. 000-50067).

10.17		—	Fifth Amendment to Amended and Restated Credit Agreement, dated as of August 3, 2012, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
10.18		—	Sixth Amendment to Amended and Restated Credit Agreement, dated as of August 30, 2012, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 30, 2012, filed with the Commission on August 31, 2012, file No. 000-50067).
10.19		—	Seventh Amendment to Amended and Restated Credit Agreement, dated as of January 28, 2013, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 28, 2013, filed with the Commission on January 29, 2013, file No. 000-50067).
10.20		—	Eighth Amendment to Amended and Restated Credit Agreement, dated as of August 28, 2013, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 28, 2013, filed with the Commission on August 30, 2013, file No. 000-50067).
10.21		—	Ninth Amendment to Amended and Restated Credit Agreement, dated as of August 28, 2013, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 22, 2014, filed with the Commission on January 22, 2014, file No. 000-50067).
10.22		—	Credit Agreement, dated as of February 20, 2014, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer thereunder, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents, Royal Bank of Canada and Bank of Montreal, as Co-Documentation Agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 20, 2014, filed with the Commission on February 21, 2014, file No. 000-50067).
10.23	†	—	Crosstex Energy Services, L.P. Severance Pay Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 1, 2011, filed with the Commission on July 1, 2011, file No. 000-50067).
10.24	†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2011, file No. 000-50536).
10.25	†*	—	Form of First Amendment to Employment Agreement Amendment.
10.26		—	Purchase Agreement, dated as of May 10, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 9, 2012, filed with the Commission on May 11, 2012, file No. 000-50067).
10.27		—	Common Unit Purchase Agreement, dated as of September 14, 2012, by and among Crosstex Energy, L.P., and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 14, 2012, filed with the Commission on September 14, 2012, file No. 000-50067).
10.28		—	Common Unit Purchase Agreement, dated as of January 9, 2013, by and among Crosstex Energy, L.P., and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 8, 2013, filed with the Commission on January 10, 2013, file No. 000-50067).
12.1	*	—	Ratio of Earnings to Fixed Charges.
21.1	*	—	List of Subsidiaries.
23.1	*	—	Consent of KPMG LLP.
31.1	*	—	Certification of the Principal Executive Officer.
31.2	*	—	Certification of the Principal Financial Officer.
32.1	*	—	Certification of the Principal Executive Officer and the Principal Financial Officer of the Company pursuant to 18 U.S.C. Section 1350.

101	*	—	The following financial information from Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2013, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011, (ii) Consolidated Balance Sheets as of December 31, 2013 and 2012, (iii) Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011, (iv) Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011, (v) Consolidated Statements of Changes in Partners' Equity for the years ended December 31, 2013, 2012 and 2011 and (vi) the Notes to Consolidated Financial Statements.

* Filed herewith.

** In accordance with the instruction on item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1 and 2.2 are not filed herewith. The agreements identify such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Commission upon request.

† As required by Item 15(a)(3), this Exhibit is identified as a compensatory benefit plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 28th day of February 2014.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, LLC, its general partner

By: /s/ BARRY E. DAVIS

Barry E. Davis,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the dates indicated by the following persons on behalf of the Registrant and in the capacities with Crosstex Energy GP, LLC, general partner of the Registrant, indicated.

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2014
/s/ RHYS J. BEST Rhys J. Best	Chairman of the Board	February 28, 2014
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 28, 2014
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Director	February 28, 2014
/s/ CECIL E. MARTIN Cecil E. Martin	Director	February 28, 2014
/s/ D. DWIGHT SCOTT D. Dwight Scott	Director	February 28, 2014
/s/ KYLE D. VANN Kyle D. Vann	Director	February 28, 2014
/s/ MICHAEL J. GARBERDING Michael J. Garberding	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 28, 2014

INDEX TO FINANCIAL STATEMENTS

Crosstex Energy, L.P. Financial Statements:

**MANAGEMENT'S REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of Crosstex Energy GP, LLC is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for Crosstex Energy, L.P. (the "Partnership"). As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended), internal control over financial reporting is a process designed by, or under the supervision of Crosstex Energy GP, LLC's principal executive and principal financial officers and effected by its Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles.

The Partnership's internal control over financial reporting is supported by written policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the Partnership's transactions and dispositions of the Partnership's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorization of the Crosstex Energy GP, LLC's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In connection with the preparation of the Partnership's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as ofDecember 31, 2013, the Partnership's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG LLP, the independent registered public accounting firm that audited the Partnership's consolidated financial statements included in this report, has issued an attestation report on the Partnership's internal control over financial reporting, a copy of which appears on page F-3 of this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2013. We also have audited Crosstex Energy, L.P.'s internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Crosstex Energy, L.P.'s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Partnership's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Crosstex Energy, L.P. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also in our opinion, Crosstex Energy, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Dallas, Texas
February 28, 2014

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets

	December 31, 2013	December 31, 2012
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57	$ 124
Accounts receivable:		
Trade, net of allowance for bad debts of $629 and $535, respectively	73,274	63,690
Accrued revenues	208,597	150,734
Imbalances	4,235	1,533
Other	8,944	3,453
Fair value of derivative assets	302	3,234
Natural gas and natural gas liquids inventory, prepaid expenses and other	17,747	11,853
Assets held for disposition	—	22,599
Total current assets	313,156	257,220
Property and equipment:		
Transmission assets	769,424	397,381
Gathering systems	726,560	723,626
Gas processing plants	614,435	586,294
Other property and equipment	128,849	86,838
Construction in process	218,107	180,976
Total property and equipment	2,457,375	1,975,115
Accumulated depreciation	(603,126)	(503,867)
Total property and equipment, net	1,854,249	1,471,248
Intangible assets, net of accumulated amortization of $227,883 and $263,305, respectively	311,976	425,005
Goodwill	153,802	152,627
Fair value of derivative assets	556	—
Investment in limited liability company	103,673	90,500
Other assets, net	21,924	25,989
Total assets	$ 2,759,336	$ 2,422,589
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 13,413	$ 4,093
Accounts payable	17,843	25,839
Accrued gas, condensate and crude oil purchases	200,585	140,344
Accrued imbalances payable	4,832	2,333
Accrued capital expenditures	25,111	23,495
Fair value of derivative liabilities	1,168	1,310
Accrued interest	26,915	26,712
Liabilities held for disposition	—	3,572
Other current liabilities	40,094	47,845
Total current liabilities	329,961	275,543
Long-term debt	1,122,202	1,036,305
Other long-term liabilities	27,030	30,256
Deferred tax liability	72,696	71,404
Fair value of derivative liabilities	755	—
Partners' equity:		
Common unitholders (91,313,391 and 66,743,632 units issued and outstanding at December 31, 2013 and 2012, respectively)	998,289	832,529
Preferred unitholders (16,642,947 and 15,072,142 units issued and outstanding at December 31, 2013 and 2012, respectively)	190,114	154,137
General partner interest (1,585,457 and 1,553,400 equivalent units outstanding at December 31, 2013 and 2012, respectively)	18,976	21,784
Accumulated other comprehensive income (loss)	(687)	631
Total partners' equity	1,206,692	1,009,081
Total liabilities and partners' equity	$ 2,759,336	$ 2,422,589

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Years ended December 31, 2013	2012	2011
	(In thousands, except per unit data)		
Revenues:			
Midstream	$ 1,943,239	$ 1,791,288	$ 2,013,942
Total revenues	1,943,239	1,791,288	2,013,942
Operating costs and expenses:			
Purchased gas, NGLs, condensate and crude oil	1,546,987	1,397,530	1,638,777
Operating expenses	150,346	130,882	111,778
General and administrative	68,061	61,308	52,801
(Gain) loss on sale of property	(1,055)	(342)	264
Loss on derivatives	2,304	1,006	7,776
Impairments	72,576	—	—
Depreciation and amortization	140,026	162,226	125,284
Total operating costs and expenses	1,979,245	1,752,610	1,936,680
Operating income (loss)	(36,006)	38,678	77,262
Other income (expense):			
Interest expense, net of interest income	(76,219)	(86,521)	(79,233)
Equity in income of limited liability company	46	3,250	—
Other income	1,367	5,053	707
Total other expense	(74,806)	(78,218)	(78,526)
Loss before non-controlling interest and income taxes	(110,812)	(39,540)	(1,264)
Income tax provision	(2,337)	(725)	(1,126)
Net loss	$ (113,149)	$ (40,265)	$ (2,390)
Less: Net loss attributable to the noncontrolling interest	—	(163)	(48)
Net loss attributable to Crosstex Energy, L.P.	$ (113,149)	$ (40,102)	$ (2,342)
Preferred interest in net loss attributable to Crosstex Energy, L.P.	$ 35,977	$ 20,779	$ 18,088
General partner interest in net loss attributable to Crosstex Energy, L.P.	$ (2,721)	$ (534)	$ (732)
Limited partners' interest in net loss attributable to Crosstex Energy, L.P.	$ (146,405)	$ (60,347)	$ (19,698)
Net loss per limited partners' unit:			
Basic common unit	$ (1.71)	$ (1.01)	$ (0.38)
Diluted common unit	$ (1.71)	$ (1.01)	$ (0.38)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income (Loss)

	Years Ended December 31,		
	2013	2012	2011
		(In thousands)	
Net loss	$ (113,149)	$ (40,265)	$ (2,390)
Hedging (gains) losses reclassified to earnings	(1,071)	(689)	1,965
Adjustment in fair value of derivatives	(247)	1,823	(1,609)
Comprehensive loss	(114,467)	(39,131)	(2,034)
Comprehensive loss attributable to non-controlling interest	—	163	48
Comprehensive loss attributable to Crosstex Energy, L.P.	$ (114,467)	$ (38,968)	$ (1,986)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity

Years ended December 31, 2013, 2012 and 2011

	Common Units		Preferred Units		General Partner Interest		Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units			
					(In thousands)				
Balance, December 31, 2010	$ 807,020	50,255	146,888	14,706	20,979	1,325	(859)	2,908	976,936
Proceeds from exercise of unit options	590	128	—	—	—	—	—	—	590
Conversion of restricted units for common units, net of units withheld for taxes	(1,798)	294	—	—	—	—	—	—	(1,798)
Capital contributions	—	—	—	—	163	9	—	—	163
Stock-based compensation	4,105	—	—	—	3,203	—	—	—	7,308
Distributions	(60,209)	—	(17,206)	—	(3,291)	—	—	—	(80,706)
Net income (loss)	(19,698)	—	18,088	—	(732)	—	—	(48)	(2,390)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	1,965	—	1,965
Adjustment in fair value of derivatives	—	—	—	—	—	—	(1,609)	—	(1,609)
Balance, December 31, 2011	730,010	50,677	147,770	14,706	20,322	1,334	(503)	2,860	900,459
Issuance of common units	232,791	15,780	—	—	3,362	207	—	—	236,153
Proceeds from exercise of unit options	436	88	—	—	—	—	—	—	436
Conversion of restricted units for common units, net of units withheld for taxes	(1,030)	198	—	—	—	—	—	—	(1,030)
Capital contributions	—	—	—	—	98	5	—	—	98
Stock-based compensation	4,904	—	—	—	4,303	—	—	—	9,207
Distributions	(76,474)	—	(14,412)	366	(5,767)	7	—	—	(96,653)
Net income (loss)	(60,347)	—	20,779	—	(534)	—	—	(163)	(40,265)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	(689)	—	(689)
Adjustment in fair value of derivatives	—	—	—	—	—	—	1,823	—	1,823
Distribution to non-controlling interest	—	—	—	—	—	—	—	(458)	(458)
Purchase of non-controlling interest	2,239	—	—	—	—	—	—	(2,239)	—
Balance, December 31, 2012	832,529	66,743	154,137	15,072	21,784	1,553	631	—	1,009,081
Issuance of common units	419,495	24,135	—	—	—	—	—	—	419,495
Proceeds from exercise of unit options	835	152	—	—	—	—	—	—	835
Conversion of restricted units for common units, net of units withheld for taxes	(1,928)	283	—	—	—	—	—	—	(1,928)
Stock-based compensation	7,088	—	—	—	7,082	—	—	—	14,170
Distributions	(113,325)	—	—	1,571	(7,169)	32	—	—	(120,494)
Net income (loss)	(146,405)	—	35,977	—	(2,721)	—	—	—	(113,149)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	(1,071)	—	(1,071)
Adjustment in fair value of derivatives	—	—	—	—	—	—	(247)	—	(247)
Balance December 31, 2013	$ 998,289	91,313	$ 190,114	16,643	$ 18,976	1,585	$ (687)	$ —	$ 1,206,692

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows from operating activities:			
Net loss	$ (113,149)	$ (40,265)	$ (2,390)
Adjustments to reconcile net loss to net cash provided by operating activities, net of assets acquired or liabilities assumed:			
Depreciation and amortization	140,026	162,226	125,284
Impairments	72,576	—	—
Non-cash stock-based compensation	14,170	9,207	7,308
(Gain) loss on sale of property and other assets	(1,055)	(3,328)	264
Deferred tax benefit	(5,452)	(1,017)	(645)
Loss on derivatives recognized in net loss	2,304	1,006	7,776
Cash paid on derivatives not recognized as revenue	(633)	(4,514)	(7,015)
Amortization of debt issue costs	6,112	5,377	6,462
Amortization of discount on notes	1,897	1,897	1,897
Distribution of earnings from limited liability company	3,296	—	—
Equity income from limited liability company	(46)	(3,250)	—
Changes in assets and liabilities:			
Accounts receivable, accrued revenue and other	(76,818)	(39,093)	44,225
Natural gas and natural gas liquids, prepaid expenses and other	(2,678)	(4,016)	(1,532)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	54,605	19,666	(38,062)
Net cash provided by operating activities	95,155	103,896	143,572
Cash flows from investing activities:			
Additions to property and equipment	(484,135)	(234,849)	(97,572)
Acquisition of business	—	(214,957)	—
Proceeds from sale of property	19,420	11,773	478
Investment in limited liability company	(30,594)	(52,250)	(35,000)
Distribution from limited liability company in excess of earnings	14,172	—	—
Net cash used in investing activities	(481,137)	(490,283)	(132,094)
Cash flows from financing activities:			
Proceeds from borrowings	481,000	806,500	471,250
Payments on borrowings	(397,000)	(570,500)	(393,308)
Payments on capital lease obligations	(3,266)	(3,111)	(3,123)
Increase (decrease) in drafts payable	9,320	(1,912)	5,854
Debt refinancing costs	(2,047)	(7,155)	(3,954)
Conversion of restricted units, net of units withheld for taxes	(1,928)	(1,030)	(1,798)
Proceeds from issuance of common units	419,495	232,791	—
Distributions to non-controlling interest	—	(458)	—
Distribution to partners	(120,494)	(96,653)	(80,706)
Proceeds from exercise of unit options	835	436	590
Contributions from general partner	—	3,460	163
Net cash provided by (used in) financing activities	385,915	362,368	(5,032)
Net increase (decrease) in cash and cash equivalents	(67)	(24,019)	6,446
Cash and cash equivalents, beginning of period	124	24,143	17,697
Cash and cash equivalents, end of period	$ 57	$ 124	$ 24,143
Cash paid for interest	$ 89,438	$ 81,237	$ 71,950
Cash paid for income taxes	$ 8,628	$ 1,706	$ 1,104

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements

December 31, 2013 and 2012

(1) Organization and Summary of Significant Agreements

(a) Description of Business

Crosstex Energy, L.P., a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, processing, transmission and marketing to producers of natural gas, natural gas liquids ("NGLs"), condensate and crude oil. We also provide crude oil, condensate and brine services to producers. We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee arrangements. We provide a variety of crude services throughout the Ohio River Valley ("ORV") which include crude oil gathering via pipelines, rail, barge and trucks and oilfield brine disposal. We also have crude oil terminal facilities in south Louisiana that provide access for crude oil producers to the premium markets in this area.

(b) Partnership Ownership

Crosstex Energy GP, LLC, the general partner of the Partnership, is a direct, wholly-owned subsidiary of Crosstex Energy, Inc. ("CEI"). As of December 31, 2013, CEI owns 16,414,830 common units in the Partnership directly and through its wholly-owned subsidiaries, representing 15.0% of the limited partner interests in the Partnership and a 1.5% general partner interest. On September 13, 2012, the board of directors of the general partner amended the partnership agreement to convert the general partner's obligation to make capital contributions to the Partnership to maintain its 2% interest in connection with the issuance of additional limited interests by the Partnership to an option of the general partner to make future capital contributions to maintain its then current general partner percentage interest.

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities and results of operations of the Partnership and its wholly-owned subsidiaries. The Partnership proportionately consolidates its undivided 50.0% interest in a gas processing plant located in the Permian Basin and its undivided 64.29% interest in a gas plant located in south Louisiana. The Partnership also consolidated its majority interest in Crosstex DC Gathering, J.V. ("CDC") until October 2012 when it acquired the remaining interest for $0.4 million. The consolidated operations are hereafter referred to collectively as the "Partnership." All material intercompany balances and transactions have been eliminated.

(2) Significant Accounting Policies

(a) Management's Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management of the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(b) Cash and Cash Equivalents

The Partnership considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(c) Natural Gas, Natural Gas Liquids, Crude Oil and Condensate Inventory

The Partnership's inventories of products consist of natural gas, NGLs, crude oil and condensate. The Partnership reports these assets at the lower of cost or market.

(d) Property, Plant, and Equipment

Property, plant and equipment consist of intrastate gas transmission systems, gas gathering systems, NGL, condensate and crude oil pipelines, natural gas processing plants, NGL fractionation plants and brine disposal wells. Gas required to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Other property and equipment is primarily comprised of the ORV trucking fleet, computer software and equipment, furniture, fixtures, leasehold improvements and office equipment. Property, plant and equipment are recorded at cost. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest costs are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use. Interest costs totaling $22.4 million, $4.0 million and $0.9 million were capitalized for the years endedDecember 31, 2013, 2012 and 2011, respectively.

Depreciation is calculated using the straight-line method based on the estimated useful life of each asset, as follows:

	Useful Lives
Transmission assets	20 - 30 years
Gathering systems	15 - 20 years
Gas processing plants	20 years
Other property and equipment	3 - 15 years

Depreciation expense of $99.6 million, $98.1 million and $77.8 million was recorded for the years endedDecember 31, 2013, 2012 and 2011, respectively. Depreciation expense also includes the amortization of assets classified as capital lease assets.

Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 360-10-05-4 requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If an impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset.

When determining whether impairment of one of our long-lived assets has occurred, the Partnership must estimate the undiscounted cash flows attributable to the asset. The Partnership's estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas, condensate and crude oil available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The volume of available gas, condensate and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas and crude oil prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors. Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

(e) Goodwill and Intangible Assets

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership evaluates goodwill for impairment annually as of July 1, 2013, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The Partnership first assesses qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

The Partnership has approximately $153.8 million and $152.6 million of goodwill at December 31, 2013 and 2012, respectively, related to the acquisition of Clearfield Energy, Inc. and its wholly-owned subsidiaries (collectively, "Clearfield") in July 2012. The goodwill recognized from the Clearfield acquisition results primarily from the value of opportunity created from the strategic asset positioning in the Utica and Marcellus shale plays which provides the Partnership with a substantial growth platform in a new geographic area. The goodwill is allocated to the ORV segment. There were no impairment charges resulting from the Partnership's July 1, 2013 impairment testing, and no event indicating impairment has occurred subsequent to that date.

Intangible assets consist of customer relationships and the value of the dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems. Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from three to twenty years. The intangible assets associated with dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems are being amortized using the units of throughput method of amortization.

The following table represents the Partnership's total purchased intangible assets at years ended December 31, 2013 and 2012 (in thousands):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
2013			
Customer relationships (1)	$ 144,210	$ (65,125)	$ 79,085
Dedicated and non-dedicated acreage	395,649	(162,758)	232,891
Total	$ 539,859	$ (227,883)	$ 311,976
2012			
Customer relationships	$ 292,658	$ (130,458)	$ 162,200
Dedicated and non-dedicated acreage	395,652	(132,847)	262,805
Total	$ 688,310	$ (263,305)	$ 425,005

(1) See Note 3-"Acquisition, Disposition and Impairments" for information related to an impairment on our Eunice customer relationships in 2013.

The weighted average amortization period for intangible assets is 19.0 years. Amortization expense for intangibles was approximately $40.5 million, $64.1 million and $47.5 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The following table summarizes the Partnership's estimated aggregate amortization expense for the next five years (in thousands):

2014	$ 35,474
2015	34,077
2016	32,591
2017	31,916
2018	31,529
Thereafter	146,389
Total	$ 311,976

(f) Investment in Limited Liability Company

On June 22, 2011, the Partnership entered into a limited liability agreement with Howard Energy Partners ("HEP") for an initial capital contribution of $35.0 million in exchange for an individual ownership interest in HEP. In 2013 and 2012, the Partnership made additional capital contributions of $30.6 million and $52.3 million, respectively. Additionally, the Partnership received distributions of $17.5 million in 2013. HEP owns midstream assets and provides midstream services to Eagle Ford Shale producers. The Partnership owns 30.6 percent of HEP and accounts for this investment under the equity method of accounting. In December 2013, Alinda Capital Partners acquired a 59% capital interest in HEP from Quanta Capital Solutions and GE Energy Financial Services. This investment is reflected on the balance sheet as "Investment in limited liability company." The Partnership's proportional share of earnings is recorded as an increase to this investment account and recorded as equity in income of limited liability company.

(g) Other Assets

Unamortized debt issuance costs totaling $21.9 million and $26.0 million as of December 31, 2013 and 2012, respectively, are included in other assets, net. Debt issuance costs are amortized into interest expense using the straight-line method over the term of the debt.

(h) Gas Imbalance Accounting

Quantities of natural gas and NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. The Partnership had imbalance payables of $4.8 million and $2.3 million at December 31, 2013 and 2012, respectively, which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $4.2 million and $1.5 million at December 31, 2013 and 2012, respectively, which are carried at the lower of cost or market value.

(i) Asset Retirement Obligations

FASB ASC 410-20-25-16 was issued in March 2005 and became effective at December 31, 2005. FASB ASC 410-20-25-16 clarifies that the term "conditional asset retirement obligation" as used in FASB ASC 410-20, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FASB ASC 410-20-25-16 provides that a liability for the fair value of a conditional asset retirement activity should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FASB ASC 410-20-25-16 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB ASC 410-20. The Partnership provided an asset retirement obligation of $0.5 million and $0.5 million as of December 31, 2013 and 2012, respectively, related to the discontinued use of the Sabine Pass plant. We did not provide any asset retirement obligations for our other facilities because we did not have sufficient information as set forth in FASB ASC 410-20-25-16 to reasonably estimate such obligations, and we have no intention of discontinuing use of any significant assets. See Note 3 "Acquisition, Disposition and Impairments" for further discussion of the Sabine Pass plant.

(j) Revenue Recognition

The Partnership recognizes revenue for sales or services at the time the natural gas, NGLs, condensate or crude oil are delivered or at the time the service is performed. The Partnership generally accrues one month of sales and the related gas, condensate and crude oil purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent month. Actual results could differ from the accrual estimates. The Partnership's purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the consolidated statement of operations in accordance with FASB ASC 605-45-45-1. Except for fee based arrangements, the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, schedules the transportation and assumes credit risk. We conduct "off-system" gas marketing operations as a service to producers on systems that we do not own. We refer to these activities as part of energy trading activities. In some cases, we earn an agency fee from the producer for arranging the marketing of the producer's natural gas. In other cases, we purchase the natural gas from the producer and enter into a sales contract with another party to sell the natural gas. The revenue and cost of sales for these activities are included in revenue on a net basis in the consolidated statement of operations.

The Partnership accounts for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

(k) Comprehensive Income (Loss)

Comprehensive income includes net income (loss) and other comprehensive income, which includes unrealized gains and losses on derivative financial instruments. Pursuant to FASB ASC 815, the Partnership records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

In February 2013, the FASB issued ASU 2013-2,*Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*("ASU 2013-2”). ASU 2013-2 requires disclosure of amounts reclassified out of accumulated other comprehensive income ("AOCI") by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of AOCI by the respective line items of net income but only if the amount reclassified is required to be reclassified to net income in its entirety in the same reporting period. For amounts not reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures that provide additional detail about those amounts. For the years ended December 31, 2013, 2012 and 2011, we reclassified cash flow hedge (gains) losses in the amounts of $(1.1) million, $(0.7) million and $2.0 million, respectively, included in other comprehensive income to revenues on the consolidated statements of operations.

(l) Derivatives

The Partnership uses derivatives to hedge against changes in cash flows related to product price, as opposed to their use for trading purposes. FASB ASC 815 requires that all derivatives be recorded on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet in fair value of derivative assets or liabilities.

Realized and unrealized gains and losses on commodity related derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, are recorded as gain or loss on derivatives in the consolidated statement of operations in the period incurred. Unrealized gains and losses on effective cash flow hedge derivatives are recorded as a component of accumulated other comprehensive income. When the hedged transaction occurs, the realized gain or loss on the hedge derivative is transferred from accumulated other comprehensive income to earnings. Realized gains and losses on commodity hedge derivatives are recognized in revenues. Settlements of derivatives are included in cash flows from operating activities.

(m) Concentrations of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited since the Partnership's customers represent a broad and diverse group of energy marketers and end users. In addition, the Partnership continually monitors and reviews credit exposure to its marketing counter-parties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. The Partnership records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Partnership had a reserve for uncollectible receivables as of December 31, 2013 and 2012 of $0.6 million and $0.5 million , respectively.

During the years ended December 31, 2013, 2012 and 2011, the Partnership had only one customer that individually represented greater than10.0% of its revenues. The customer is located in the LIG segment and represented 12.6%, 10.5% and 12.3% of the consolidated revenues for each of the years endedDecember 31, 2013, 2012 and 2011, respectively. As the Partnership continues to grow and expand, the relationship between individual customer sales and consolidated total sales is expected to continue to change. While this customer represents a significant percentage of revenues, the loss of this customer would not have a material adverse impact on the Partnership's results of operations because the gross operating margin received from transactions with this customer is not material to the Partnership's gross operating margin.

(n) Legal Costs Expected to be Incurred in Connection with a Loss Contingency

Legal costs incurred in connection with a loss contingency are expensed as incurred.

(o) Environmental Costs

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For the years ended December 31, 2013, 2012 and 2011, such expenditures were not significant.

(p) Share-Based Awards

The Partnership recognizes compensation cost related to all stock-based awards, including stock options, in its consolidated financial statements in accordance with FASB ASC 718. The Partnership and CEI each have similar unit or share-based payment plans for employees, which are described below. Share-based compensation associated with CEI's share-based compensation plans awarded to officers and employees of the general partner of the Partnership are recorded by the Partnership since CEI has no substantial or managed operating activities other than its interest in the Partnership. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Cost of share-based compensation charged to general and administrative expense	$ 12,334	$ 7,964	$ 6,157
Cost of share-based compensation charged to operating expense	1,836	1,243	1,151
Total amount charged to income	$ 14,170	$ 9,207	$ 7,308

(q) Recent Accounting Pronouncements

We have reviewed all recently issued accounting pronouncements that became effective during the year ended December 31, 2013, and have determined that none would have a material impact on our Consolidated Financial Statements.

(3) Acquisition, Disposition and Impairments

(a) Acquisition

On July 2, 2012, the Partnership, through a wholly-owned subsidiary, acquired all of the issued and outstanding common stock of Clearfield. Clearfield was a well-established crude oil, condensate and brine services company with operations in Ohio, Kentucky and West Virginia. Clearfield's business included crude oil pipelines, a barge loading terminal on the Ohio River, a rail loading terminal on the Ohio Central Railroad network, a trucking fleet and brine disposal wells. All of these assets are now included in the Partnership's ORV segment.

The Partnership paid approximately $215.4 million in cash (before working capital and certain purchase price adjustments) for the acquisition and the purchase was funded with proceeds from the senior notes offering in May 2012.

Included in the Clearfield acquisition were three local distribution companies, or LDCs, which the Partnership marketed for sale and were classified as held for disposition on the balance sheet as of December 31, 2012. The Partnership chose not to apply discontinued operations presentation on the income statement as the related amounts were immaterial during the period of the Partnership's ownership. On October 15, 2012, the Partnership entered into an agreement to sell the LDCs for an amount of $19.4 million and the sale was completed on January 18, 2013.

The goodwill recognized from the Clearfield acquisition results primarily from the value of opportunity created from the strategic asset positioning in the Utica and Marcellus shale plays which provides the Partnership with a substantial growth platform in a new geographic area. The Partnership finalized the purchase price allocation related to the Clearfield acquisition during July 2013. As a result of the purchase price adjustments since December 31, 2012, the Partnership recognized an increase of goodwill acquired from the transaction of $1.2 million.

The Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer life of approximately 20 years.

The Partnership assumed a long-term liability related to additional benefit obligations. Also, the Partnership assumed a long-term liability related to inactive easement commitments for a period of 10 years.

Purchase Price Allocation in Clearfield Acquisition

The following table is a summary of the consideration paid in the Clearfield acquisition and the purchase price allocation for the fair value of the assets acquired and liabilities assumed at the acquisition date.

Purchase Price Allocation (in thousands):		
Purchase Price to Clearfield Energy, Inc.	$	215,397
Total purchase price	$	215,397
Assets acquired:		
Current assets	$	17,622
Assets held for disposition		19,358
Property, plant, and equipment		91,422
Goodwill		153,802
Intangibles		37,600
Liabilities assumed:		
Current liabilities		(28,274)
Liabilities held for disposition		(1,400)
Deferred taxes		(65,228)
Long term liabilities		(9,505)
Total purchase price	$	215,397

For the period from July 2, 2012 to December 31, 2012, the Partnership recognized$108.0 million of midstream revenue related to properties acquired in the Clearfield acquisition. For the period from July 2, 2012 to December 31, 2012, the Partnership recognized $94.2 million of operating costs and expenses related to properties acquired in the Clearfield acquisition.

Pro Forma Information

The following unaudited pro forma condensed financial data for the year ended December 31, 2012 and 2011 gives effect to the Clearfield acquisition as if it had occurred on January 1, 2011. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

	Year Ended	
	December 31, 2012	December 31, 2011
	(in thousands except for per unit data)	
Pro forma total revenues	$ 1,897,199	$ 2,266,868
Pro forma net loss	$ (42,546)	$ (16,968)
Pro forma net loss attributable to Crosstex Energy, L.P.	$ (42,383)	$ (16,920)
Pro forma net loss per common unit:		
Basic and Diluted	$ (0.98)	$ (0.55)

(b) Intangible Asset Impairment

In August 2013, the Partnership shut down the Eunice processing plant, which is located in south Louisiana and is part of our PNGL segment, due to adverse economics driven by low NGL prices and low processing volumes which we do not see improving in the near future based on forecasted pricing. The Partnership recorded an impairment expense of $72.6 million during the third quarter of 2013 related to the intangible assets for the terminated customer relationships attributable to the plant shut down.

(c) Long-Lived Assets Impairments

Changes in Operations During 2013 and 2012.

Our Sabine Pass plant held a contract with a third-party to fractionate the raw-make NGLs produced by the Sabine Pass plant. The primary term of the contract expired in March 2012 and was renewed on a month-to-month basis during the remainder of 2012. Due to the anticipated termination of this third-party fractionation agreement in early 2013, we began accelerating depreciation of this facility during the third quarter of 2012. The plant also had some equipment failures during the fourth quarter of 2012. In January 2013, we ceased plant operations because the cost to repair the equipment could not be supported by an existing month-to-month fractionation agreement. Depreciation and amortization expense during the fourth quarter of 2012 was changed to accelerate the remaining non-recoverable costs associated with the plant. Total depreciation and amortization of $28.9 million was recognized for the Sabine Pass plant during 2012. The Sabine Pass plant contributed gross operating margin of $2.0 million and $2.7 million for the years ended December 31, 2012 and 2011, respectively. The net book value for the plant is $18.9 million as of December 31, 2013 and represents the plant's fair market value. Although we do not have specific plans at this time to relocate the Sabine Pass plant, we may utilize it elsewhere in our operations.

(4) Long-Term Debt

As of December 31, 2013 and 2012, long-term debt consisted of the following (in thousands):

	2013	2012
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2013 and December 31, 2012 was 3.2% and 4.3%, respectively	$ 155,000	$ 71,000
Senior unsecured notes (due 2018), net of discount of $7.8 million and $9.7 million, respectively, which bear interest at the rate of 8.875%	717,202	715,305
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250,000	250,000
Debt classified as long-term	$ 1,122,202	$ 1,036,305

Maturities. Maturities for the long-term debt as of December 31, 2013 are as follows (in thousands):

2014	$ —
2015	—
2016	155,000
2017	—
2018	725,000
Thereafter	250,000
Subtotal	1,130,000
Less discount	(7,798)
Total outstanding debt	$ 1,122,202

Existing Credit Facility. In January 2013, the Partnership amended the existing credit facility to, among other things, eliminate the existing and any future step-up in the maximum permitted consolidated leverage ratio for acquisitions. All references herein to our existing credit facility include, as applicable, such amendments.

In August 2013, the Partnership amended the existing credit facility to, among other things, (i) allow the Partnership to make additional investments in joint ventures and subsidiaries that are not guarantors of the Partnership's obligations under the existing credit facility, (ii) decrease the minimum consolidated interest coverage ratio (as defined in the existing credit facility, being generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) and (iii) increase the maximum permitted consolidated leverage ratio (as defined in the existing credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges). See the chart below for the ratios, as amended.

In January 2014, the Partnership amended the existing credit facility to redefine the credit agreement's definition of "change of control" such that the consummation of the previously announced business combination with Devon Energy Corporation will not constitute a change of control under the existing credit facility.

As of December 31, 2013, there was $155.0 million of borrowing and $59.7 million in outstanding letters of credit under the existing credit facility leaving approximately $420.3 million available for future borrowing based on a borrowing capacity of$635.0 million. However, the financial covenants in the existing credit facility limit the amount of funds that we can borrow. As of December 31, 2013, based on the financial covenants in the existing credit facility, we could borrow approximately$207.1 million of additional funds.

The existing credit facility is guaranteed by substantially all of our subsidiaries and is secured by first priority liens on substantially all of our assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in substantially all of our subsidiaries. We may prepay all loans under the existing credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The existing credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, extraordinary receipts, equity issuances and debt incurrences, but these mandatory prepayments do not require any reduction of the lenders' commitments under the existing credit facility.

Under the existing credit facility, borrowings bear interest at our option at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. We pay a per annum fee (as described below) on all letters of credit issued under the existing credit facility and a commitment fee of between 0.375% and 0.50% per annum on the unused availability under the existing credit facility. The commitment fee, letter of credit fee and the applicable margins for the interest rate vary quarterly based on our leverage ratio (as defined in the existing credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans and Letter of Credit Fees	Letter of Commitment Fees
Greater than or equal to 4.50 to 1.00	2.00%	3.00%	0.50%
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	1.75%	2.75%	0.50%
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	1.50%	2.50%	0.50%
Greater than or equal to 3.00 to 1.00 and less than 3.50 to 1.00	1.25%	2.25%	0.50%
Less than 3.00 to 1.00	1.00%	2.00%	0.38%

The existing credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The minimum consolidated interest coverage ratio (as defined in the existing credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is 2.25 to 1.0 for the fiscal quarters ending March 31, 2014, June 30, 2014, September 30, 2014 and December 31, 2014, with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter. The maximum permitted senior leverage ratio (as defined in the existing credit facility, but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non cash charges) is 2.75 to 1.00. The maximum permitted leverage ratio (as defined in the existing credit facility, but generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 5.50 to 1.0 for the fiscal quarters ending March 31, 2014, June 30, 2014 and September 30, 2014, with a maximum ratio of 5.25 to 1.0 for each fiscal quarter ending thereafter.

In addition, the existing credit facility contains various covenants that, among other restrictions, limit the Partnership's ability to:

- grant or assume liens;
- make investments;
- incur or assume indebtedness;
- engage in mergers or acquisitions;
- sell, transfer, assign or convey assets;
- repurchase the Partnership's equity, make distributions and certain other restricted payments;
- change the nature of the Partnership's business;
- engage in transactions with affiliates;
- enter into certain burdensome agreements;
- make certain amendments to the omnibus agreement or the Partnership's subsidiaries' organizational documents;
- prepay the senior unsecured notes and certain other indebtedness; and
- enter into certain hedging contracts.

The existing credit facility permits the Partnership to make quarterly distributions to unitholders so long as no default exists under the existing credit facility.

Each of the following is an event of default under the existing credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation, or covenant in the existing credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- The Partnership's or any of its subsidiaries default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- certain ERISA events involving the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries; and
- a change in control (as defined in the existing credit facility).

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under the existing credit facility will immediately become due and payable. If any other event of default exists under the existing credit facility, the lenders may accelerate the maturity of the obligations outstanding under the existing credit facility and exercise other rights and remedies. In addition, if any event of default exists under the existing credit facility, the lenders may commence foreclosure or other actions against the collateral.

If any default occurs under the existing credit facility, or if the Partnership is unable to make any of the representations and warranties in the existing credit facility, the Partnership will be unable to borrow funds or have letters of credit issued under the existing credit facility.

The Partnership expects to be in compliance with the covenants in the existing credit facility for at least the next twelve months.

Senior Unsecured Notes. On February 10, 2010, the Partnership and Crosstex Energy Finance Corporation issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "2018 Notes") due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity including the original issue discount ("OID"). Interest payments on the 2018 Notes are due semi-annually in arrears in February and August. On May 24, 2012, the Partnership and Crosstex Energy Finance Corporation issued $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes" and together with the 2018 Notes, the "Senior Notes") due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments on the 2022 Notes are due semi-annually in arrears in June and December.

The indentures governing the Senior Notes contain covenants that, among other things, limit the Partnership's ability and the ability of certain of its subsidiaries to:

- sell assets including equity interests in its subsidiaries;
- pay distributions on, redeem or repurchase units or redeem or repurchase its subordinated debt (as discussed in more detail below);
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from its restricted subsidiaries to the Partnership;
- consolidate, merge or transfer all or substantially all of its assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; or
- engage in certain business activities.

The indentures provide that if the Partnership's fixed charge coverage ratio (the ratio of consolidated cash flow to fixed charges, which generally represents the ratio of adjusted EBITDA to interest charges with further adjustments as defined per the indenture) for the most recently ended four full fiscal quarters is not less than 2.0 to 1.0, the Partnership will be permitted to pay distributions to its unitholders in an amount equal to available cash from operating surplus (each as defined in our partnership agreement) with respect to its preceding fiscal quarter plus a number of items, including the net cash proceeds received by the Partnership as a capital contribution or from the issuance of equity interests since the date of the indenture, to the extent not previously expended. If the Partnership's fixed charge coverage ratio is less than 2.0 to 1.0 , the Partnership will be able to pay distributions to its unitholders in an amount equal to a specified basket (less amounts previously expended pursuant to such basket), plus the same number of items discussed in the preceding sentence to the extent not previously expended. The Partnership was in compliance with this covenant as of December 31, 2013.

If the Senior Notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, many of the covenants discussed above will terminate. Our current ratings on our bonds from Moody's Investors Service, Inc. and Standard & Poor's Rating Services are B1 and B+, respectively.

On or after February 15, 2014, the Partnership may redeem all or a part of the notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on February 15, 2014, 102.219%

for the twelve-month period beginning February 15, 2015 and 100.00% for the twelve-month period beginning on February 15, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the notes.

The Partnership may redeem up to 35% of the 2022 Notes at any time prior to June 1, 2015 in an amount not greater than the cash proceeds from equity offerings at a redemption price of 107.125% of the principal amount of the 2022 Notes (plus accrued and unpaid interest to the redemption date) provided that:

- at least 65% of the aggregate principal amount of the 2022 Notes remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 180 days of the date of the closing of the equity offering.

Prior to June 1, 2017, the Partnership may redeem all or a part of the 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date.

On or after June 1, 2017, the Partnership may redeem all or a part of the 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Each of the following is an event of default under the indenture:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation, or other covenant in the indenture, subject to the cure periods for certain failures;
- the Partnership's or any of its subsidiaries' default under other indebtedness that exceeds a certain threshold amount;
- failures by the Partnership or any of its subsidiaries to pay final judgments that exceed a certain threshold amount; and
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries.

If an event of default relating to bankruptcy or other insolvency events occurs, the Senior Notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the Senior Notes may accelerate the maturity of the Senior Notes and exercise other rights and remedies.

Successful completion of the Contribution and the Mergers would trigger a mandatory repurchase offer under the terms of the indenture governing the Partnership's 2018 Notes at a purchase price equal to 101% of the aggregate principal amount of the 2018 Notes repurchased, plus accrued and unpaid interest, if any. In certain circumstances, completion of the Contribution and the Mergers also could trigger a mandatory repurchase offer under the terms of the indenture governing the Partnership's 2022 Notes if, within 90 days of consummation of the transactions, the Partnership experiences a rating downgrade of the 2022 Notes by either Moody’s or S&P.

Non Guarantors. The Senior Notes are jointly and severally guaranteed by each of the Partnership's current material subsidiaries (the "Guarantors"), with the exception of our regulated Louisiana subsidiaries (which may only guarantee up to $500.0 million of the Partnership's debt) and Crosstex Energy Finance Corporation (a wholly owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Partnership's indebtedness, including the Senior Notes). Guarantors may not sell or otherwise dispose of all or substantially all of their properties or assets to, or consolidate with or merge into another company if such a sale would cause a default under the terms of the Senior Notes. The Partnership has no assets or operations independent of its subsidiaries. There are no significant restrictions on the ability of the Partnership or any Subsidiary Guarantor to obtain funds from its subsidiaries by dividend or loan. Since certain wholly owned subsidiaries do not guarantee the Senior Notes, the condensed consolidating financial statements of the guarantors and non-guarantors as of the years ended December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011 are disclosed below in accordance with Rule 3-10 of Regulation S-X. Comprehensive income (loss) is not included in the condensed consolidating statements of operations of the guarantors and non-guarantors for the years ended December 31, 2013, 2012 and 2011 as these amounts are not considered material.

Condensed Consolidating Balance Sheets

December 31, 2013

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
ASSETS				
Total current assets	$ 302,202	$ 10,954	$ —	$ 313,156
Property, plant and equipment, net	1,626,550	227,699	—	1,854,249
Total other assets	591,931	—	—	591,931
Total assets	$ 2,520,683	$ 238,653	$ —	$ 2,759,336
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 311,053	$ 18,908	$ —	$ 329,961
Long-term debt	1,122,202	—	—	1,122,202
Other long-term liabilities	100,481	—	—	100,481
Partners' capital	986,947	219,745	—	1,206,692
Total liabilities & partners' capital	$ 2,520,683	$ 238,653	$ —	$ 2,759,336

December 31, 2012

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
ASSETS				
Total current assets	$ 246,165	$ 11,055	$ —	$ 257,220
Property, plant and equipment, net	1,276,097	195,151	—	1,471,248
Total other assets	694,121	—	—	694,121
Total assets	$ 2,216,383	$ 206,206	$ —	$ 2,422,589
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 273,151	$ 2,392	$ —	$ 275,543
Long-term debt	1,036,305	—	—	1,036,305
Other long-term liabilities	101,660	—	—	101,660
Partners' capital	805,267	203,814	—	1,009,081
Total liabilities & partners' capital	$ 2,216,383	$ 206,206	$ —	$ 2,422,589

Condensed Consolidating Statements of Operations

For the Year Ended December 31, 2013

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,894,987	$ 73,719	$ (25,467)	$ 1,943,239
Total operating costs and expenses	(1,971,970)	(32,742)	25,467	(1,979,245)
Operating income (loss)	(76,983)	40,977	—	(36,006)
Interest expense, net	(76,219)	—	—	(76,219)
Other income	1,413	—	—	1,413
Income (loss) before non-controlling interest and income taxes	(151,789)	40,977	—	(110,812)
Income tax provision	(2,337)	—	—	(2,337)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (154,126)	$ 40,977	$ —	$ (113,149)

For the Year Ended December 31, 2012

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,734,199	$ 84,457	$ (27,368)	$ 1,791,288
Total operating costs and expenses	(1,742,796)	(37,182)	27,368	(1,752,610)
Operating income	(8,597)	47,275	—	38,678
Interest expense, net	(86,456)	(65)	—	(86,521)
Other income	8,303	—	—	8,303
Income (loss) before non-controlling interest and income taxes	(86,750)	47,210	—	(39,540)
Income tax provision	(711)	(14)	—	(725)
Less: Net loss attributable to non-controlling interest	—	(163)	—	(163)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (87,461)	$ 47,359	$ —	$ (40,102)

For the Year Ended December 31, 2011

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,954,612	$ 86,577	$ (27,247)	$ 2,013,942
Total operating costs and expenses	(1,925,234)	(38,693)	27,247	(1,936,680)
Operating income	29,378	47,884	—	77,262
Interest expense, net	(79,230)	(3)	—	(79,233)
Other income	707	—	—	707
Income (loss) before non-controlling interest and income taxes	(49,145)	47,881	—	(1,264)
Income tax provision	(1,110)	(16)	—	(1,126)
Less: Net loss attributable to non-controlling interest	—	(48)	—	(48)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (50,255)	$ 47,913	$ —	$ (2,342)

Condensed Consolidating Statements of Cash Flow

For the Year Ended December 31, 2013

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by operating activities	$ 43,765	$ 51,390	$ —	$ 95,155
Net cash flows used in investing activities	$ (454,793)	$ (26,344)	$ —	$ (481,137)
Net cash flows provided by (used in) financing activities	$ 385,915	$ (25,046)	$ 25,046	$ 385,915

For the Year Ended December 31, 2012

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by operating activities	$ 42,798	$ 61,098	$ —	$ 103,896
Net cash flows used in investing activities	$ (487,668)	$ (2,615)	$ —	$ (490,283)
Net cash flows provided by (used in) financing activities	$ 362,368	$ (58,104)	$ 58,104	$ 362,368

For the Year Ended December 31, 2011

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by operating activities	$ 81,883	$ 61,689	$ —	$ 143,572
Net cash flows used in investing activities	$ (129,806)	$ (2,288)	$ —	$ (132,094)
Net cash flows provided by (used in) financing activities	$ (5,032)	$ (58,606)	$ 58,606	$ (5,032)

(5) Income Taxes

The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The net tax basis in the Partnership's assets and liabilities is less than the reported amounts on the financial statements by approximately $627.3 million as of December 31, 2013. The Partnership is subject to the margin tax enacted by the state of Texas on May 1, 2006.

The LIG entities the Partnership formed to acquire the stock of LIG Pipeline Company and its subsidiaries are treated as taxable corporations for income tax purposes. The entity structure was formed to effect the matching of the tax cost to the Partnership of a step-up in the basis of the assets to fair market value with the recognition of benefits of the step-up by the Partnership. A deferred tax liability of $8.2 million was recorded at the acquisition date. The deferred tax liability represents future taxes payable on the difference between the fair value and tax basis of the assets acquired. The remaining deferred tax liability of $6.1 million related to the LIG acquisition will be paid during 2014.

The Partnership formed a wholly-owned corporate entity to acquire the common stock of Clearfield and assumed the carryover tax basis of the Clearfield assets. A net deferred tax liability of $71.8 million was recorded at the acquisition date. This deferred tax liability represents future tax payable on the difference between the fair value and tax basis of the assets acquired and is expected to become payable no later than 2027.

The Partnership provides for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis that will reverse in future periods (in thousands).

	Years Ended December 31,		
	2013	2012	2011
Current tax provision	$ 7,789	$ 1,742	$ 1,771
Deferred tax (benefit)	(5,452)	(1,017)	(645)
Tax provision	$ 2,337	$ 725	$ 1,126

A reconciliation of the provision for income taxes is as follows (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Federal income tax on taxable corporation at statutory rate (35%)	$ 1,758	$ 241	$ 199
State income taxes, net	579	484	927
Income tax provision	$ 2,337	$ 725	$ 1,126

The principal component of the Partnership's net deferred tax liability is as follows (in thousands):

	Years Ended December 31,	
	2013	2012
Deferred income tax assets—long-term:		
Accrued expenses	$ 1,251	$ 1,455
Deferred transaction cost	—	863
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets-current	—	(7,075)
Property, plant, equipment, and intangible assets-long-term	(73,576)	(73,722)
Net deferred tax liability	$ (72,325)	$ (78,479)

A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (in thousands):

Balance as of December 31, 2011	$	4,213
Decreases related to prior year tax positions		(609)
Increases related to current year tax positions		508
Balance as of December 31, 2012	$	4,112
Decreases related to prior year tax positions		(1,132)
Increases related to current year tax positions		824
Balance as of December 31, 2013	$	3,804

The $1.1 million decrease in prior year tax position mainly consists of unrecognized tax benefits at December 31, 2012 that expired in 2013. Unrecognized tax benefits as of December 31, 2013 of $3.8 million if recognized, would affect the effective tax rate. It is unknown when the remaining uncertain tax position will be resolved.

Per company accounting policy election, $0.2 million of penalties and interest related to prior year tax positions was recorded to income tax expense in 2013. In the event interest or penalties are incurred with respect to income tax matters, the Partnership's policy will be to include such items in income tax expense. As of December 31, 2013, tax years 2010 through 2013 remain subject to examination by the Internal Revenue Service and tax years 2009 through 2013 remain subject to examination by various state taxing authorities.

(6) Partners' Capital

(a) Sale of Preferred Units

On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units (the "preferred units") to an affiliate of Blackstone/GSO Capital Solutions for net proceeds of $120.8 million. The Partnership's general partner made a ccntribution of $2.6 million in connection with the issuance to maintain its then 2% general partner interest. The 14,705,882 preferred units were convertible by the holders thereof at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. The preferred units were not redeemable, but were entitled to a quarterly distribution equal to the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unit holders, subject to certain adjustments. Income was allocated to the preferred units in an amount equal to the quarterly distribution with respect to the period earned. During 2012 and 2011, the Partnership paid cash distributions on its preferred units of $14.4 million and $17.2 million, respectively.

Beginning in the third quarter of 2012 through the fourth quarter of 2013, the distributions on the preferred units were paid-in-kind ("PIK"). The number of PIK preferred units distributed is determined using a fixed price of $13.25. The distributions for the year ended December 31, 2012 were paid-in-kind through the issuance of 366,260 preferred units and the distributions for the year ended December 31, 2013 were paid-in-kind through the issuance of 1,570,806 preferred units. A distribution on the preferred units of $0.36 per unit was declared for the three months ended December 31, 2013, which was also paid-in-kind on February 12, 2014 in the amount of 452,186 preferred units.

The Partnership had the right to force conversion of the preferred units if (i) the daily volume weighted average trading price of the common units is greater than $12.75 per unit for 20 out of the trailing 30 trading days ending on two trading days before the date on which the Partnership delivers notice of such conversion, and (ii) the average trading volume of common units exceeds a specified number of common units (the “trading volume threshold”) for 20 out of the trailing 30 trading days ending on two trading days before the date on which the Partnership delivers notice of such conversion. On February 27, 2014, the board of directors of the Partnership’s general partner amended the Partnership’s partnership agreement to reduce the trading volume threshold from 250,000 common units to 215,000, and on that same date the Partnership delivered a notice of conversion of all outstanding preferred units.

(b) Issuance of Common Units

In June 2013, the Partnership issued 8,280,000 common units representing limited partner interests in the Partnership (including 1,080,000 common units issued pursuant to the exercise of the underwriters' option to purchase additional common units) at a public offering price of $20.33 per common unit for net proceeds of $162.0 million. In January 2013, the Partnership issued 8,625,000 common units representing limited partner interests in the Partnership at a public offering price of $15.15 per common unit for net proceeds of $125.5 million. Concurrently with the public offering in a privately negotiated transaction, the Partnership issued 2,700,000 common units representing limited partner interests in the Partnership at an offering price of $14.55 per unit for net proceeds of $39.3 million. The net proceeds from both common unit offerings were used for capital expenditures for currently identified projects, including the Cajun-Sibon projects, and for general partnership purposes. Crosstex Energy GP, LLC did not exercise its option to make a general partner contribution to maintain its then current general partner percentage interest in connection with these offerings.

In September 2012, the Partnership issued 5,660,378 common units representing limited partner interests in the Partnership at an offering price of $13.25 per unit for net proceeds of $74.8 million. The net proceeds from the common units issuance were used primarily to fund the Partnership's currently identified projects, including the Cajun-Sibon NGL pipeline expansion, and for general partnership purposes. Crosstex Energy GP, LLC did not exercise its option to make a general partner contribution to maintain its then current general partner percentage interest in connection with this offering.

In May 2012, the Partnership issued 10,120,000 common units representing limited partner interests in the Partnership at a public offering price of $16.28 per unit for net proceeds of $158.0 million. In addition, Crosstex Energy GP, LLC made a general partner contribution of $3.4 million in connection with the issuance to maintain its then current general partner interest. The net proceeds from the common units offering were used for general partnership purposes.

In March 2013, the Partnership entered into an Equity Distribution Agreement (the “EDA”) with BMO Capital Markets Corp. (“BMOCM”). Pursuant to the terms of the EDA, the Partnership could from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Sales of such common units could be made by means of ordinary brokers’ transactions through the facilities of the NASDAQ Global Select Market LLC at market prices, in block transactions or as otherwise agreed by BMOCM and the Partnership.

In May 2013, the Partnership entered into an Equity Distribution Agreement ("Replacement EDA") with BMOCM. This Replacement EDA replaced the previous EDA. Pursuant to the terms of the Replacement EDA, the Partnership could from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Sales of such common units could be made by means of ordinary brokers’ transactions through the facilities of the NASDAQ Global Select Market LLC at market prices, in block transactions or as otherwise agreed by BMOCM and the Partnership.

Through December 31, 2013, the Partnership sold an aggregate of 1,181,628 common units and 3,348,213 common units under the EDA and Replacement EDA, respectively, generating proceeds of approximately $20.9 million and $72.3 million (net of approximately $0.3 million and $0.9 million of commissions to BMOCM), respectively. The Partnership used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness. The Partnership exhausted its capacity under the Replacement EDA on January 3, 2014.

(c) Cash Distributions

Unless restricted by the terms of the Partnership's credit facility and/or senior unsecured note indentures, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. As described under *(a) Sale of Preferred Units* above, the preferred units are entitled to a quarterly distribution equal to the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. The general partner is not entitled to a distribution in relation to its percentage interest with respect to the quarterly preferred distribution of $0.2125 per unit that is made solely to the preferred unitholders. The general partner is entitled to a distribution in relation to its percentage interest with respect to all distributions made to common unitholders. If the distributions are in excess of $0.2125 per unit, distributions are made 100% to the common and preferred unitholders minus the general partner's percentage interest, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved.

Under the quarterly incentive distribution provisions, generally the Partnership's general partner is entitled to13% of amounts the Partnership distributes in excess of$0.25 per unit, 23% of the amounts the Partnership distributes in excess of$0.3125 per unit and 48% of amounts the Partnership distributes distribute in excess of$0.375 per unit. Incentive distributions totaling $6.4 million, $4.5 million, and $2.4 million were earned by our general partner for the years endedDecember 31, 2013, 2012 and 2011, respectively. The Partnership paid annual distributions per common unit of $1.33, $1.31 and $1.17 in the years ended December 31, 2013, 2012 and 2011, respectively.

The Partnership's fourth quarter distribution on its common units was$0.36 per unit which was paid on February 12, 2014.

(d) Earnings per Unit and Dilution Computations

The Partnership had common units and preferred units outstanding during the years endedDecember 31, 2013, 2012 and 2011.

The preferred units are entitled to a quarterly distribution equal to the greater of$0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Income is allocated to the preferred units in an amount equal to the quarterly distribution with respect to the period end for the first and second quarters of 2012. For the third and fourth quarters of 2012 and the fiscal year 2013, income allocation is based on the fair value of the PIK Preferred Units distributed, which are priced at the market value of common units on the record date of such distributions.

As required under FASB ASC 260-10-45-61A unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, for earnings per unit calculations. The following table reflects the computation of basic earnings per limited partner units for the periods presented (in thousands except per unit amounts):

	Years Ended December 31,		
	2013	2012	2011
Limited partners' interest in net loss	$ (146,405)	$ (60,347)	$ (19,698)
Distributed earnings allocated to:			
Common units(1)	$ 115,042	$ 77,794	$ 62,238
Unvested restricted units	1,620	1,306	1,187
Total distributed earnings	$ 116,662	$ 79,100	$ 63,425
Undistributed earnings allocated to:			
Common units	$ (259,413)	$ (137,144)	$ (81,616)
Unvested restricted units	(3,653)	(2,303)	(1,507)
Total undistributed earnings (loss)	$ (263,066)	$ (139,447)	$ (83,123)
Net loss allocated to:			
Common units	$ (144,371)	$ (59,350)	$ (19,377)
Unvested restricted units	(2,034)	(997)	(321)
Total limited partners' interest in net loss	$ (146,405)	$ (60,347)	$ (19,698)
Total basic and diluted net loss per unit:			
Basic and diluted common unit	$ (1.71)	$ (1.01)	$ (0.38)

(1) Represents distributions declared to common unitholders.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2013, 2012 and 2011 (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Basic and diluted earnings per unit:			
Weighted average limited partner common units outstanding	84,589	58,935	50,590

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented. All common unit equivalents were antidilutive for the years ended December 31, 2013, 2012 and 2011 because the limited partners were allocated a net loss in these periods.

When quarterly distributions are made pro-rata to common and preferred unitholders, net income for the general partner consists of incentive distributions to the extent earned, a deduction for stock-based compensation attributable to CEI's stock options and restricted shares and the general partner interest of the original Partnership's net income (loss) adjusted for the CEI stock-based compensation specifically allocated to the general partner. When quarterly distributions are made solely to the preferred unitholders, the net income for the general partner consists of the CEI stock-based compensation deduction and the general partner interest percentage of the Partnership's net income (loss) after the allocation of income to the preferred unitholders with respect to their preferred distribution adjusted for the CEI stock-based compensation specifically allocated to the general partner. The net income (loss) allocated to the general partner is as follows (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Income allocation for incentive distributions	$ 6,390	$ 4,489	$ 2,372
Stock-based compensation attributable to CEI's restricted shares	(6,973)	(4,205)	(3,119)
General partner interest in net income (loss)	(2,138)	(818)	15
General partner share of net loss	$ (2,721)	$ (534)	$ (732)

(7) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership's managing general partner has a long-term incentive plan for its employees, directors and affiliates who perform services for the Partnership. The Partnership accounts for share-based compensation in accordance with FASB ASC 718, which requires that compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. On May 9, 2013, the Partnership’s unitholders approved the amendment and restatement of the Crosstex Energy GP, LLC Long-Term Incentive Plan (the “Plan”), which increased the number of common units representing limited partner interests in the Partnership authorized for issuance under the Plan by 3,470,000 common units to an aggregate of 9,070,000 common units and made certain other technical amendments.

The Partnership and CEI each have similar unit or share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plan awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no substantial or managed operating activities other than its interest in the Partnership.

(b) Restricted Incentive Units

Awards of restricted incentive units are rights that entitle the grantee to receive common units of the Partnership upon the vesting of such restricted incentive unit. In addition, the restricted incentive units will become exercisable upon a change of control of the Partnership or its general partner.

The restricted incentive units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted incentive units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted incentive units are forfeited. The restricted incentive units granted in 2013, 2012 and 2011 generally cliff vest after three years of service.

The restricted incentive units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted incentive unit activity for the year ended December 31, 2013 is provided below:

Crosstex Energy, L.P. Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,003,159	$ 13.31
Granted	625,339	16.19
Vested*	(396,927)	9.50
Forfeited	(52,648)	13.52
Non-vested, end of period	1,178,923	$ 16.11
Aggregate intrinsic value, end of period (in thousands)	$ 32,538	

* Vested units include 114,831 units withheld for payroll taxes paid on behalf of employees.

In March 2013, the Partnership issued 57,897 restricted incentive units with a fair value of $1.0 million to officers and certain employees as bonus payments for 2012, which vested immediately and are included in the restricted incentive units granted and vested line items above.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2013, 2012, and 2011 are provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, L.P. Restricted Incentive Units:	2013	2012	2011
Aggregate intrinsic value of units vested	$ 6,750	$ 3,850	$ 6,438
Fair value of units vested	$ 3,771	$ 2,097	$ 5,945

As of December 31, 2013, there was $7.4 million of unrecognized compensation cost related to non-vested restricted incentive units. That cost is expected to be recognized over a weighted-average period of 1.2 years.

(c) Unit Options

Unit options will have an exercise price that is not less than 100% of the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership or its general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior to estimate expected forfeiture rates. The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant. The Partnership used the simplified method to calculate the expected term.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant. The unit options granted generally vest based on 3 years of service (one-third after each year of service). There have been no options granted since 2009.

A summary of the unit option activity for the years ended December 31, 2013, 2012, and 2011 is provided below:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	349,018	$ 7.25	451,574	$ 6.99	611,311	$ 6.77
Exercised	(151,795)	5.50	(87,857)	4.96	(128,477)	4.61
Forfeited	(3,109)	23.60	(14,699)	13.39	(31,260)	12.83
Outstanding, end of period	194,114	$ 8.36	349,018	$ 7.25	451,574	$ 6.99
Options exercisable at end of period	194,114	$ 8.36	286,715	$ 7.52	315,742	$ 7.42
Weighted average contractual term (years) end of period:						
Options outstanding	5.2		6.1		7.2	
Options exercisable	5.2		6.0		6.9	
Aggregate intrinsic value end of period (in thousands):						
Options outstanding	$ 3,829		$ 3,016		$ 4,648	
Options exercisable	$ 3,829		$ 2,483		$ 3,260	

A summary of the unit options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value of units vested (value per Black-Scholes-Merton option pricing model at date of grant) during the years ended December 31, 2013, 2012, and 2011 is provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options:	2013	2012	2011
Intrinsic value of units options exercised	$ 2,104	$ 988	$ 1,527
Fair value of unit options vested	$ 254	$ 277	$ 563

As of December 31, 2013, all options were vested and fully expensed.

(d) Crosstex Energy, Inc.'s Restricted Stock

The Crosstex Energy, Inc. long-term incentive plans provide for the award of restricted stock (collectively, "Awards") for up to 8,975,000 shares of Crosstex Energy, Inc.'s common stock. On May 9, 2013, CEI's stockholders approved the amendment and restatement of the Crosstex Energy, Inc. 2009 Long-Term Incentive Plan (the “CEI Plan”), which increased the number of shares of CEI's common stock authorized for issuance under the CEI Plan by 1,785,000 shares to an aggregate of 4,385,000 shares of common stock and made certain other technical amendments.

As of January 1, 2014, approximately 2,464,665 shares remained available under the long-term incentive plans for future issuance to participants. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Awards that are forfeited, terminated or expire unexercised become immediately available for additional awards under the long-term incentive plan.

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. CEI's restricted stock granted in 2013, 2012 and 2011 generally cliff vest after three years of service. A summary of the restricted stock activity which includes officers and employees of the Partnership and directors of the general partner of the Partnership for the year ended December 31, 2013, is provided below:

Crosstex Energy, Inc. Restricted Shares:	Number of Shares	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,329,162	$ 9.75
Granted	632,912	15.08
Vested*	(445,177)	7.43
Forfeited	(63,864)	11.69
Non-vested, end of period	1,453,033	$ 12.69
Aggregate intrinsic value, end of period (in thousands)	$ 51,089	

* Vested shares include 123,791 shares withheld for payroll taxes paid on behalf of employees.

In March 2013, CEI issued 60,018 restricted shares with a fair value of $1.0 million to officers and certain employees as bonus payments for 2012, which vested immediately and are included in restricted shares granted and vested in the above line items.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value of shares vested (market value at date of grant) during the years ended December 31, 2013, 2012, and 2011 is provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, Inc. Restricted Shares:	2013	2012	2011
Aggregate intrinsic value of shares vested	$ 7,593	$ 4,099	$ 3,915
Fair value of shares vested	$ 3,307	$ 1,754	$ 5,623

As of December 31, 2013 there was $7.4 million of unrecognized compensation costs related to CEI restricted shares for directors, officers and employees. The cost is expected to be recognized over a weighted average period of 1.1 years.

(e) Crosstex Energy, Inc.'s Stock Options

CEI stock options have not been granted since 2005. A summary of the stock option activity includes officers and employees of the Partnership and directors of CEI for the years ended December 31, 2013, 2012, and 2011 is provided below:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	37,500	$ 6.50	37,500	$ 6.50	37,500	$ 6.50
Exercised	(22,500)	6.50	—	—	—	—
Outstanding, end of period	15,000	$ 6.50	37,500	$ 6.50	37,500	$ 6.50
Options exercisable at end of period	15,000	$ 6.50	37,500	$ 6.50	37,500	$ 6.50

A summary of the stock options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value of shares vested (value per Black-Scholes-Merton option pricing model at date of grant) during the years ended December 31, 2013, 2012, and 2011 is provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, Inc. Stock Options:	**2013**	**2012**	**2011**
Intrinsic value of stock options exercised	$ 317	$ —	$ —
Fair value of stock options vested	$ —	$ —	$ —

As of December 31, 2013, all options were vested and fully expensed.

(8) Derivatives

Commodity Swaps

The Partnership manages its exposure to fluctuation in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge price and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

The Partnership commonly enters into various derivative financial transactions which it does not designate as hedges. These transactions include "swing swaps," "third party on-system financial swaps," "storage swaps," "basis swaps," "processing margin swaps," "liquids swaps" and "put options." Swing swaps are generally short-term in nature (one month), and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers and simultaneously enters into the derivative transaction. Storage swap transactions protect against changes in the value of gas that the Partnership has stored to serve various operational requirements. Basis swaps are used to hedge basis location price risk due to buying gas into one of our systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge fractionation spread risk at our processing plants relating to the option to process versus bypassing our equity gas. Liquids financial swaps are used to hedge price risk on liquid swaps not otherwise designated as cash flow hedges. Put options are purchased to hedge against declines in pricing and as such represent options, not obligations, to sell the related underlying volumes at a fixed price.

The components of loss on derivatives in the consolidated statements of operations relating to commodity swaps are (in thousands):

	Years Ended December 31,		
	2013	**2012**	**2011**
Change in fair value of derivatives that are not designated for hedge accounting	$ 1,674	$ (3,473)	$ 726
Realized losses on derivatives	633	4,514	7,015
Ineffective portion of derivatives designated for hedge accounting	(3)	(35)	(158)
Net losses related to commodity swaps	$ 2,304	$ 1,006	$ 7,583
Put option premium mark to market	—	—	193
Losses on derivatives	$ 2,304	$ 1,006	$ 7,776

The fair value of derivative assets and liabilities relating to commodity swaps are as follows (in thousands):

	December 31, 2013	December 31, 2012
Fair value of derivative assets—current, designated	$ 9	$ 724
Fair value of derivative assets—current, non-designated	293	2,510
Fair value of derivative assets-long term, non-designated	556	—
Fair value of derivative liabilities—current, designated	(705)	(105)
Fair value of derivative liabilities—current, non-designated	(463)	(1,205)
Fair value of derivative liabilities-long term, non-designated	(755)	—
Net fair value of derivatives	$ (1,065)	$ 1,924

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets at December 31, 2013 (all gas volumes are expressed in MMBtus, liquids volumes are expressed in gallons and condensate volumes are expressed in barrels). The remaining term of the contracts extend no later than December 2016. Changes in the fair value of the Partnership's mark to market derivatives are recorded in earnings in the period incurred. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings. The ineffective portion is recorded in earnings immediately.

Transaction Type	December 31, 2013 Volume	December 31, 2013 Fair Value
	(In thousands)	
*Cash Flow Hedges:**		
Liquids swaps (short contracts)	(8,567)	$ (696)
Total swaps designated as cash flow hedges		$ (696)
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	1,457	$ (14)
Physical offsets to swing swap transactions (short contracts)	(1,147)	—
Swing swaps (short contracts)	(78)	2
Physical offsets to swing swap transactions (long contracts)	78	—
Processing margin hedges—liquids (short contracts)	(2,662)	(270)
Processing margin hedges—gas (long contracts)	291	40
Liquids swaps—non-designated (long contracts)	50,400	(537)
Liquids swaps—non-designated (short contracts)	(50,400)	428
Storage swap transactions (short contracts)	(100)	(18)
Total mark to market derivatives		$ (369)

* All are gas contracts except for liquids swaps (designated or non-designated), processing margin hedges—liquids, storage swap transactions—liquids inventory and storage swap transactions—condensate inventory.

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits and monitors the appropriateness of these limits on an ongoing basis. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements ("ISDAs") that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2013 of $0.7 million would be reduced to$0.2 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

Impact of Cash Flow Hedges

The impact of realized gains or losses from derivatives designated as cash flow hedge contracts in the consolidated statements of operations is summarized below (in thousands):

	Years Ended December 31,		
Increase (decrease) in Midstream revenue	**2013**	**2012**	**2011**
Liquids	$ 768	$ 1,381	$ (2,772)

Natural Gas

As of December 31, 2013, the Partnership has no balances in accumulated other comprehensive income (loss) related to natural gas.

Liquids

As of December 31, 2013, an unrealized derivative fair value net loss of$0.7 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss), all of which is expected to reclassified into earnings by December 2014. The actual reclassification to earnings will be based on mark to market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, swing swaps, basis swaps, storage swaps, processing margin swaps and liquids swaps are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as a loss on derivatives in the consolidated statement of operations. The Partnership estimates the fair value of all of its derivative contracts using actively quoted prices. The estimated fair value of derivative contracts by maturity date was as follows (in thousands):

	Maturity Periods			
	Less than one year	**One to two years**	**More than two years**	**Total fair value**
December 31, 2013	$ (170)	$ 61	$ (260)	$ (369)

(9) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

FASB ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Partnership's derivative contracts primarily consist of commodity swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in hierarchy.

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in thousands):

	December 31,	
	2013	2012
	Level 2	Level 2
Commodity Swaps*	$ (1,065)	$ 1,924
Total	$ (1,065)	$ 1,924

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income at each measurement date. The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for credit risk of the Partnership and/or the counterparty as required under FASB ASC 820.

Fair Value of Financial Instruments

The estimated fair value of the Partnership's financial instruments has been determined by the Partnership using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value, thus, the estimates provided below are not necessarily indicative of the amount the Partnership could realize upon the sale or refinancing of such financial instruments (in thousands):

	December 31, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,122,202	$ 1,203,201	$ 1,036,305	$ 1,118,875
Obligations under capital lease	21,988	23,371	25,257	27,667

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The Partnership had $155.0 million in borrowings under its revolving credit facility included in long-term debt as ofDecember 31, 2013 and $71.0 million in borrowings under this credit facility as of December 31, 2012. Borrowings under the credit facility accrue interest under a floating interest rate structure so the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2013 and December 31, 2012, the Partnership also had borrowings totaling $717.2 million and $715.3 million, net of discount, respectively, under the 2018 Notes with a fixed rate of8.875% and borrowings of $250.0 million as of December 31, 2013 and 2012 under the 2022 Notes with a fixed rate of7.125%. The fair value of all senior unsecured notes as ofDecember 31, 2013 and 2012 was based on Level 1 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

(10) Transactions with Related Parties

CEI paid the Partnership $1.0 million, $0.7 million and $0.8 million during the years ended December 31, 2013, 2012 and 2011, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI. This reimbursement is evaluated on an annual basis. Officers and employees that perform services for CEI provide an estimate of the portion of their time devoted to such services. A portion of their annual compensation (including bonuses, payroll taxes and other benefit costs) is allocated to CEI for reimbursement based on these estimates. In addition, an administrative burden is added to such costs to reimburse us for additional support costs, including, but not limited to, consideration for rent, office support and information service support.

(11) Commitments and Contingencies

(a) Leases—Lessee

The Partnership has operating leases for office space, office and field equipment.

The following table summarizes the Partnership's remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in thousands):

2014	$	10,194
2015		10,331
2016		8,374
2017		5,205
2018		5,771
Thereafter		15,733
	$	55,608

Operating lease rental expense in the years ended December 31, 2013, 2012, and 2011 was approximately $28.1 million, $23.2 million and $21.9 million, respectively.

(b) Employment and Severance Agreements

Certain members of management of the Partnership are parties to employment and/or severance agreements with the general partner. The employment and severance agreements provide those managers with severance payments in certain circumstances and, in the case of employment agreements, prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

(c) Environmental Issues

The Partnership acquired LIG Pipeline Company and its subsidiaries on April 1, 2004. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. The seller, AEP, has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third party company pursuant to which the remediation costs associated with these sites have been assumed by this third party company that specializes in remediation work. To date, 23 of the 25 sites requiring remediation have been completed and have received a "No Further Action" status from the Louisiana Department of Environmental Quality. The remaining two sites continuing with remediation efforts are expected to reach closure in2014. The Partnership does not expect to incur any material liability with these sites; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations.

(d) Other

The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

At times, the Partnership's gas-utility and common carrier subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain. As a result, the Partnership (or its subsidiaries) is party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

From time to time, owners of property located near our processing facilities or compression facilities file lawsuits against us. These suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property.

Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. InJanuary 2012, a plaintiff in one of these lawsuits was awarded a judgment of$2.0 million. The Partnership has appealed the matter and has posted a bond to secure the judgment pending its resolution. The Partnership has accrued a $2.0 million liability related to this matter and reflected the related expense in operating expenses in the fourth quarter of 2011. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies, seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans, but was removed to federal court. The amount of damages is unspecified. The Partnership's subsidiary, Crosstex LIG, LLC, is one of the named defendants as the owner of pipelines in the area. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

(12) Segment Information

Identification of operating segments is based principally upon regions served. The Partnership's reportable segments consist of the natural gas gathering, processing and transmission operations located in north Texas and in the Permian Basin in west Texas ("NTX"), the pipelines and processing plants located in Louisiana ("LIG"), the south Louisiana processing and NGL assets ("PNGL") and rail, truck, pipeline, and barge facilities in the Ohio River Valley ("ORV"). The Partnership's sales are derived from external domestic customers.

The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital, debt financing costs and its investment in HEP. Profit in the corporate segment for the years ended 2013 and 2012 includes the operating activity for intersegment eliminations.

Summarized financial information concerning the Partnership's reportable segments is shown in the following table:

	LIG	NTX	PNGL	ORV	Corporate	Totals
			(In thousands)			
Year Ended December 31, 2013:						
Sales to external customers	$ 491,217	$ 321,025	$ 850,245	$ 280,752	$ —	$ 1,943,239
Sales to affiliates	89,081	72,960	22,144	—	(184,185)	—
Purchased gas, NGLs, condensate and crude oil	(495,807)	(229,687)	(777,989)	(227,689)	184,185	(1,546,987)
Operating expenses	(31,699)	(53,771)	(30,736)	(34,140)	—	(150,346)
Segment profit	$ 52,792	$ 110,527	$ 63,664	$ 18,923	$ —	$ 245,906
Gain (loss) on derivatives	$ 92	$ (1,768)	$ (289)	$ (339)	$ —	$ (2,304)
Depreciation, amortization and impairments	$ (12,631)	$ (79,303)	$ (106,412)	$ (11,407)	$ (2,849)	$ (212,602)
Capital expenditures	$ 45,569	$ 23,175	$ 394,514	$ 16,432	$ 4,465	$ 484,155
Identifiable assets	$ 300,593	$ 991,332	$ 1,003,596	$ 317,818	$ 145,997	$ 2,759,336
Year Ended December 31, 2012:						
Sales to external customers	$ 561,389	$ 269,302	$ 852,560	$ 108,037	$ —	$ 1,791,288
Sales to affiliates	225,542	96,177	145,569	—	(467,288)	—
Purchased gas, NGLs, condensate and crude oil	(678,188)	(180,116)	(924,240)	(82,274)	467,288	(1,397,530)
Operating expenses	(33,817)	(55,582)	(29,601)	(11,882)	—	(130,882)
Segment profit	$ 74,926	$ 129,781	$ 44,288	$ 13,881	$ —	$ 262,876
Gain (loss) on derivatives	$ 3,440	$ (4,405)	$ (41)	$ —	$ —	$ (1,006)
Depreciation, amortization and impairments	$ (13,865)	$ (83,493)	$ (57,653)	$ (4,860)	$ (2,355)	$ (162,226)
Capital expenditures	$ 4,059	$ 45,235	$ 182,782	$ 3,893	$ 8,944	$ 244,913
Identifiable assets	$ 278,842	$ 1,057,504	$ 632,962	$ 316,927	$ 136,354	$ 2,422,589
Year Ended December 31, 2011:						
Sales to external customers	$ 811,216	$ 332,026	$ 870,700	$ —	$ —	$ 2,013,942
Sales to affiliates	128,130	100,527	40,185	—	(268,842)	—
Purchased gas, NGLs, condensate and crude oil	(809,471)	(262,708)	(835,440)	—	268,842	(1,638,777)
Operating expenses	(35,434)	(48,807)	(27,537)	—	—	(111,778)
Segment profit	$ 94,441	$ 121,038	$ 47,908	$ —	$ —	$ 263,387
Loss on derivatives	$ (6,145)	$ (1,896)	$ 265	$ —	$ —	$ (7,776)
Depreciation, amortization and impairments	$ (13,602)	$ (76,535)	$ (31,271)	$ —	$ (3,876)	$ (125,284)
Capital expenditures	$ 2,820	$ 73,069	$ 25,618	$ —	$ 2,629	$ 104,136
Identifiable assets	$ 304,372	$ 1,113,431	$ 460,865	$ —	$ 76,663	$ 1,955,331

The following table reconciles the segment profits reported above to the operating income as reported in the consolidated statements of operations (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Segment profits	$ 245,906	$ 262,876	$ 263,387
General and administrative expenses	(68,061)	(61,308)	(52,801)
Loss on derivatives	(2,304)	(1,006)	(7,776)
Gain (loss) on sale of property	1,055	342	(264)
Depreciation, amortization and impairments	(212,602)	(162,226)	(125,284)
Operating income (loss)	$ (36,006)	$ 38,678	$ 77,262

(13) Immaterial Correction of Prior Period Financial Statements

During the year ended December 31, 2013, the Partnership determined certain immaterial corrections were required for previously-issued financial statements for the year ended December 31, 2012, as discussed below. The corrections did not impact the Partnership's operating income and were not considered material to the Partnership's revenues and costs for the applicable periods.

The Partnership determined that revenues and purchased gas costs related to a new processing arrangement were improperly reduced from revenue and purchased gas costs which resulted in equal understatements of revenues and purchased gas costs in its previously-issued financial statements for the year ended December 31, 2012. As a result both revenues and purchased gas were understated by $135.4 million for the year ended December 31, 2012. The following table reflects the revenues, purchased gas costs and total operating costs and expenses as previously reported and as adjusted for the year ended December 31, 2012 (in thousands):

	Year Ended December 31, 2012
As previously reported:	
Total revenues	$ 1,655,851
Purchased gas, NGLs, condensate and crude oil	$ 1,262,093
Total operating costs and expenses	$ 1,617,173
Operating income	$ 38,678
As adjusted:	
Total revenues	$ 1,791,288
Purchased gas, NGLs, condensate and crude oil	$ 1,397,530
Total operating costs and expenses	$ 1,752,610
Operating income	$ 38,678

(14) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
2013:					
Revenues	$ 445,689	$ 454,589	$ 468,362	$ 574,599	$ 1,943,239
Operating income (loss)	$ 14,886	$ 8,231	$ (61,827)	$ 2,704	$ (36,006)
Net loss attributable to the Crosstex Energy, L.P.	$ (5,952)	$ (10,629)	$ (78,838)	$ (17,730)	$ (113,149)
Preferred interest in net loss attributable to Crosstex Energy, L.P.	$ 7,079	$ 8,131	$ 8,286	$ 12,481	$ 35,977
General partner interest in net loss	$ (1,244)	$ (312)	$ (1,451)	$ 286	$ (2,721)
Limited partners' interest in net loss attributable to Crosstex Energy, L.P.	$ (11,787)	$ (18,448)	$ (85,673)	$ (30,497)	$ (146,405)
Loss per limited partner unit-basic	$ (0.15)	$ (0.23)	$ (0.95)	$ (0.38)	$ (1.71)
Loss per limited partner unit-diluted	$ (0.15)	$ (0.23)	$ (0.95)	$ (0.38)	$ (1.71)
2012:					
Revenues	$ 425,959	$ 394,402	$ 444,947	$ 525,980	$ 1,791,288
Operating income (loss)	$ 22,735	$ 19,209	$ 1,797	$ (5,063)	$ 38,678
Net loss attributable to the non-controlling interest	$ (38)	$ (71)	$ (54)	$ —	$ (163)
Net income (loss) attributable to the Crosstex Energy, L.P.	$ 2,979	$ (2,440)	$ (16,100)	$ (24,541)	$ (40,102)
Preferred interest in net income (loss) attributable to Crosstex Energy, L.P.	$ 4,853	$ 4,853	$ 5,640	$ 5,433	$ 20,779
General partner interest in net income (loss)	$ (71)	$ (40)	$ (309)	$ (114)	$ (534)
Limited partners' interest in net income (loss) attributable to Crosstex Energy, L.P.	$ (1,803)	$ (7,253)	$ (21,431)	$ (29,860)	$ (60,347)
Loss per limited partner unit-basic	$ (0.03)	$ (0.13)	$ (0.34)	$ (0.51)	$ (1.01)
Loss per limited partner unit-diluted	$ (0.03)	$ (0.13)	$ (0.34)	$ (0.51)	$ (1.01)

(15) Subsequent Events

2022 Notes. On January 3, 2014, the Partnership instructed the trustee to deliver a notice of redemption for approximately$53.5 million in aggregate principal amount of its 2022 Notes (the “Redeemed Notes”), representing approximately 21% of the aggregate principal amount of the outstanding 2022 Notes. The Redeemed Notes were redeemed effective as of February 2, 2014 for a total redemption price equal to$1,083.32 per $1,000 principal amount redeemed. Following the completion of the redemption, approximately $196.5 million aggregate principal amount of the 2022 Notes remain outstanding.

Credit Facility. On February 20, 2014, the Partnership entered into a$1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the “new credit facility”). The Partnership's ability to borrow funds and obtain letters of credit under the new credit facility is conditioned upon, among other things, the closing of the Contribution and the prior or concurrent termination of the Partnership’s existing credit facility. Upon the termination of the existing credit facility, the liens securing the existing credit facility will be released and the Partnership’s subsidiaries will no longer guarantee its indebtedness and will be released as guarantors under the indentures governing the Partnership’s Senior Notes.

The new credit facility will mature on the fifth anniversary of the initial funding date, unless the Partnership requests, and the requisite lenders agree, to extend it pursuant to its terms. The new credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the new credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If the Partnership consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA will increase to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under the new credit facility bear interest at the Partnership's option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. The applicable margins vary depending on the partnership's credit rating. Upon breach by the Partnership of certain covenants governing the new credit facility, amounts outstanding under the new credit facility, if any, may become due and payable immediately.

AMENDMENT NO. 5 TO

SIXTH AMENDED AND RESTATED

AGREEMENT OF LIMITED PARTNERSHIP

OF

CROSSTEX ENERGY, L.P.

This Amendment No. 5 to SIXTH Amended and Restated Agreement of Limited Partnership of CROSSTEX ENERGY, L.P. (this "Amendment"), dated as of February 27, 2014, is entered into by Crosstex Energy GP, LLC, a Delaware limited liability company (the "General Partner"), as general partner of Crosstex Energy, L.P., a Delaware limited partnership (the "Partnership"). Capitalized terms used but not defined herein are used as defined in the Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007, as amended by Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of December 20, 2007, as amended by Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., effective as of January 1, 2007, as amended by Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010, and as amended by Amendment No. 4 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of September 13, 2012 (as so amended, the "Partnership Agreement").

RECITALS:

WHEREAS, the General Partner desires to amend the Partnership Agreement to modify the terms of the Series A Convertible Preferred Units;

WHEREAS, Section 13.1(d)(i) of the Partnership Agreement provides that the General Partner may amend any provision of the Partnership Agreement, without the approval of any Partner or Assignee, to reflect a change that, in the discretion of the General Partner, does not adversely affect the Limited Partners (including any particular class of Partnership Interests as compared to other classes of Partnership Interests) in any material respect;

WHEREAS, acting pursuant to the power and authority granted to it under Section 13.1(d)(i) of the Partnership Agreement, the General Partner has determined that this Amendment does not adversely affect the Limited Partners (including any particular class of Partnership Interests as compared to other classes of Partnership Interests) in any material respect; and

WHEREAS, in accordance with Section 5.15(b)(v)(B) of the Partnership Agreement, the sole holder of the Series A Convertible Preferred Units has consented to the amendments to the terms of the Series A Convertible Preferred Units that are set forth in this Amendment.

NOW THEREFORE, the Partnership Agreement is hereby amended as follows:

Section 1. Amendment. The number "250,000" in clause (ii) of Section 5.15(b)(viii)(C) is hereby deleted and replaced with the number "215,000."

Section 2. General Authority. The appropriate officers of the General Partner are hereby authorized to make such further clarifying and conforming changes they deem necessary or appropriate, and to interpret the Partnership Agreement, to give effect to the intent and purpose of this Amendment.

Section 3. Ratification of Partnership Agreement. Except as expressly modified and amended herein, all of the terms and conditions of the Partnership Agreement shall remain in full force and effect.

Section 4. Governing Law. This Amendment will be governed by and construed in accordance with the laws of the State of Delaware.

IN WITNESS WHEREOF, the General Partner has executed this Amendment to be effective as of the date first set forth above.

GENERAL PARTNER:
Crosstex Energy GP, LLC

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: *Executive Vice President and Chief Financial Officer*

FORM OF
FIRST AMENDMENT TO EMPLOYMENT AGREEMENT

This First Amendment to Employment Agreement (this "***Amendment***") is made and entered into this ____ day of _______, ____, by and between Crosstex Energy GP, LLC ("***Company***") and ______________ ("***Employee***").

WHEREAS, Company and Employee have entered into an Employment Agreement ("***Agreement***") dated February 27, 2012;

WHEREAS, Company and Employee now wish to amend the Agreement to extend the expiration date of the Agreement from February 28, 2014 to August 31, 2014, as provided below:

NOW, THEREFORE, in consideration of the mutual covenants set forth herein and in the Agreement, Company and Employee agree to amend the Agreement as follows:

1. Capitalized terms not otherwise defined in this Amendment shall have the meanings set forth in the Agreement.

2. Section 4.1(a) of the Agreement shall be deleted in its entirety and replaced with the following:

"Subject to Section 4.1(b) and Section 4.1(c), the term of this Agreement shall commence as of the Effective Date, and shall continue for a period of thirty (30) months."

3. This Amendment shall be binding upon and inure to the benefit of Company and Employee and their respective successors or permitted assigns. In the event of a conflict between the provisions of this Amendment, and the Agreement, the terms of this Amendment shall control.

4. Except as provided herein, the terms, conditions and provisions of the Agreement shall remain in full force and effect.

IN WITNESS WHEREOF, the Company has caused this First Amendment to Employment Agreement to be duly executed, and Employee has hereunto set his hand, as of the day and year set forth above.

CROSSTEX ENERGY GP, LLC

By: ________________________________
Name:
Title:

EMPLOYEE:

____
Name:

EXHIBIT 12.1

RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Earnings Before Fixed charges:					
Earnings from continuing operations before non-controlling interest or tax	$ (110,812)	$ (39,540)	$ (1,264)	$ (24,708)	$ (75,695)
Capitalized interest	(22,431)	(4,048)	(900)	(128)	(1,076)
Amortization of capitalized interest	2,114	992	790	745	738
Income from equity investment	(46)	(3,250)	—	—	—
Distributed income from equity investment	17,468	—	—	—	—
Non-controlling interest	—	(163)	(48)	19	60
Total earnings before fixed charges	$ (113,707)	$ (46,009)	$ (1,422)	$ (24,072)	$ (75,973)
Fixed charges:					
Interest expense includes discontinued operations	$ 76,219	$ 86,521	$ 79,233	$ 87,035	$ 125,903
Capitalized interest includes discontinued operations	22,431	4,048	900	128	1,076
Total fixed charges	$ 98,650	$ 90,569	$ 80,133	$ 87,163	$ 126,979
Total earnings & fixed charges	$ (15,057)	$ 44,560	$ 78,711	$ 63,091	$ 51,006
Ratio of earnings to fixed charges	—	0.49	0.98	0.72	0.40
Deficiency	$ (113,707)	$ (46,009)	$ (1,422)	$ (24,072)	$ (75,973)

Exhibit 21.1

LIST OF SUBSIDIARIES

Name of Subsidiary	State of Organization
Crosstex Operating GP, LLC	Delaware
Crosstex Energy Services GP, LLC	Delaware
Crosstex Energy Services, L.P.	Delaware
Crosstex Energy Finance Corporation	Delaware
Crosstex Gulf Coast Marketing Ltd.	Texas
Crosstex CCNG Processing Ltd.	Texas
Crosstex Louisiana Energy, L.P.	Delaware
Crosstex Louisiana Gathering, LLC	Louisiana
Crosstex LIG, LLC	Louisiana
Crosstex Tuscaloosa, LLC	Louisiana
Crosstex LIG Liquids, LLC	Louisiana
Crosstex DC Gathering Company, J.V.	Texas
Crosstex North Texas Pipeline, L.P.	Texas
Crosstex North Texas Gathering, L.P.	Texas
Crosstex Texas NGL Pipeline, LLC	Texas
Crosstex Processing Services, LLC	Delaware
Crosstex Pelican, LLC	Delaware
Crosstex Crude Marketing, LLC	Delaware
Crosstex NGL Marketing, L.P.	Texas
Crosstex NGL Pipeline, L.P.	Texas
Sabine Pass Plant Facility Joint Venture	Texas
Crosstex Permian, LLC	Texas
Crosstex Permian II, LLC	Texas
Crosstex ORV Holdings, Inc.	Delaware
Appalachian Oil Purchasers, LLC	Delaware
Kentucky Oil Gathering, LLC	Delaware
M&B Gas Services, LLC	Delaware
Ohio Oil Gathering II, LLC	Delaware
Ohio Oil Gathering III, LLC	Delaware
Ohio River Valley Pipeline, LLC	Delaware
OOGC Disposal Company I, LLC	Delaware
West Virginia Oil Gathering, LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.

We consent to the incorporation by reference in the registration statements No. 333-107025, 333-127645, 333-159140 and 333-188678 on Forms S-8, No 333-188047 and 333-188041 on Form S-3 of Crosstex Energy, L.P. and subsidiaries of our reports dated February 28, 2014, with respect to the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2013, and the effectiveness of internal control over financial reporting as of December 31, 2013, which report appears in the December 31, 2013 annual report on Form 10-K of Crosstex Energy, L.P. and subsidiaries.

/s/ KPMG LLP

Dallas, Texas
February 28, 2014

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy GP, LLC, the general partner of the registrant, certify that:

1. I have reviewed this annual report on Form 10-K of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BARRY E. DAVIS

BARRY E. DAVIS,
President and Chief Executive Officer
(principal executive officer)

Date: February 28, 2014

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of the registrant, certify that:

1. I have reviewed this annual report on Form 10-K of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ MICHAEL J. GARBERDING

MICHAEL J. GARBERDING,
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: February 28, 2014

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Crosstex Energy, L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and Michael J. Garberding, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

	/s/ BARRY E. DAVIS
	Barry E. Davis
	President and Chief Executive Officer
Date: February 28, 2014	
	/s/ MICHAEL J. GARBERDING
	Michael J. Garberding
	Executive Vice President and Chief Financial Officer
Date: February 28, 2014	

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.