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, 2012

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 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 $703,617,810 on June 30, 2012, based on $16.40 per unit, the closing price of the Common Units as reported on The NASDAQ Global Select Market on such date.

At February 15, 2013, there were 78,245,974 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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CROSSTEX ENERGY, L.P.

PART I

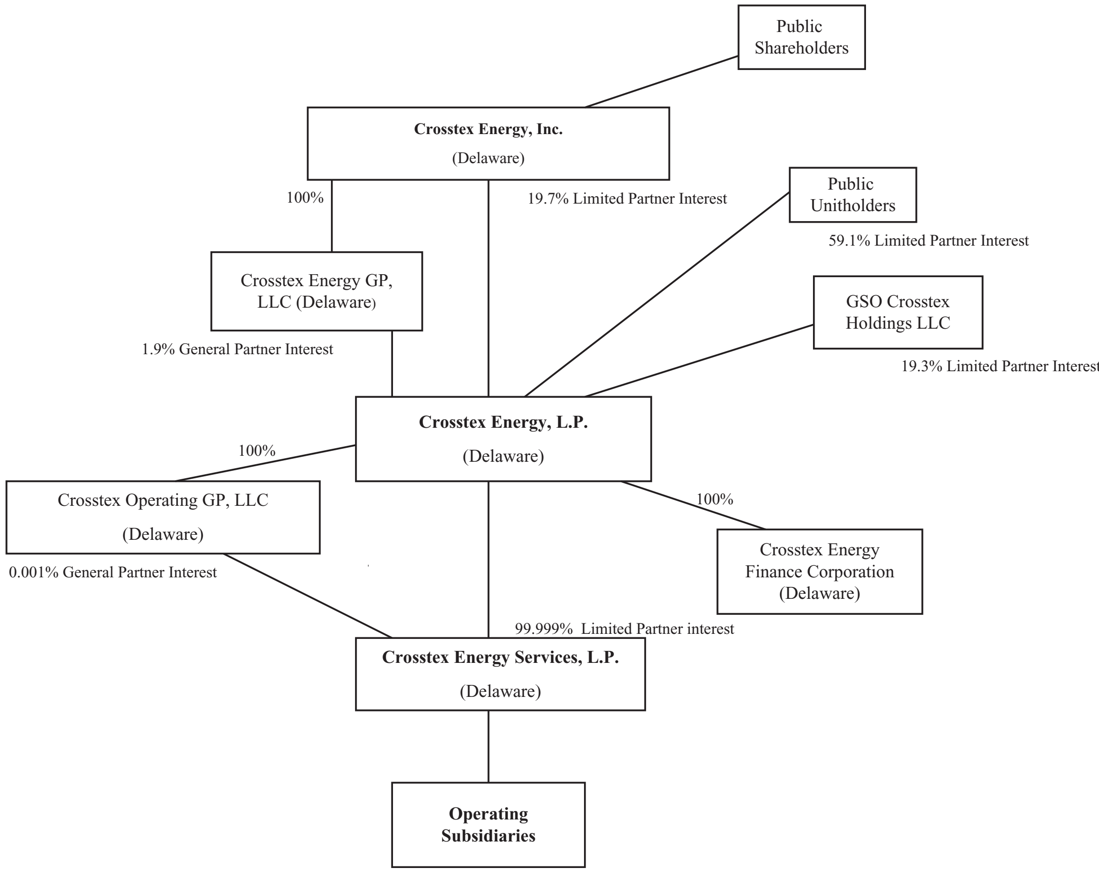
Item 1. *Business*

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 web-site 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, 2012.



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 July 12, 2002. We primarily focus on providing midstream energy services, including gathering, processing, transmission and marketing, to producers of natural gas, NGLs and crude oil. We also provide crude oil, condensate and brine services to producers. Our midstream energy asset network includes approximately 3,500 miles of pipelines, ten 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 14 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. In addition, we purchase natural gas from producers not connected to our gathering systems for resale and sell natural gas on behalf of producers for a fee. We provide a variety of crude services throughout the ORV which include crude oil gathering via pipelines, barges 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. 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. Our oil gathering and transmission systems consist of trucking facilities, pipelines 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 butanes and natural gasoline.

Our assets include the following:

- *North Texas Assets.* Our North Texas assets consist of gathering systems with total capacity of approximately 1.2 Bcf/d, processing facilities with a total processing capacity of approximately 340 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 which extend from the Haynesville Shale in north Louisiana to onshore production in south central and southeast Louisiana and processing facilities with a total processing capacity of 335 MMcf/d.
- *South Louisiana Processing and NGL Assets.* Our south Louisiana natural gas processing and liquid assets include approximately 1.7 Bcf/d of processing capacity, 54,000 Bbls/d of fractionation capacity, 3.1 million barrels of underground NGL storage, 440 miles of liquids transport lines and a crude oil terminal with a total capacity of 4,500 Bbls/d.

- *Ohio River Valley Assets.* Our Ohio River Valley assets include a 4,500-barrel-per-hour crude oil barge loading terminal on the Ohio River, a crude oil rail loading terminal on the Ohio Central Railroad network that is being expanded to a 20-spot operation and approximately 200 miles of crude oil 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 seven existing brine disposal wells with an injection capacity of approximately 10,000 Bbls/d. We currently hold two additional brine well permits in Ohio, one of which is under development. In addition, we own more than 2,500 miles of unused rights-of-way.

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. In 2013, we will continue to focus on the same business strategy that we believe we successfully executed in 2012.

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 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. Examples of these activities are discussed more fully under “Recent Growth Developments” below.
- *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. For example, we expanded our scale and diversification in 2012 by acquiring assets in the Ohio River Valley that give us the opportunity to expand our crude and condensate logistics business. These assets provide us with an established presence in the rapidly developing Utica and Marcellus Shale plays.

During 2012, we participated in several projects and transactions that expanded our size and outreach while increasing our fee-based business, including: (1) the construction and operation of a cryogenic plant in the Permian Basin in west Texas as part of a joint venture with Apache Corporation, (2) our equity investment in HEP in the Eagle Ford Shale natural gas play in south Texas and (3) the expansion and operation of crude oil terminals in south Louisiana. In addition, we began construction of Phase I of the Cajun-Sibon pipeline extension project that will expand our NGL pipeline system and fractionation facilities in south Louisiana. We expect this phase of the project will be completed and operational by mid-2013. We also initiated Phase II of the Cajun-Sibon project that we expect to complete in late 2014. These projects are discussed more fully under “Recent Growth Developments” below.

Our growth plans for 2013 align with our business strategy. We believe through the execution of this strategy, we will continue to drive growth and deliver value to our investors, customers and employees by leveraging our well-positioned asset base. This platform consists of various fee-based projects with geographic and product diversity which will allow us to:

- *Diversify our revenue streams with the continued emphasis on the NGL, crude oil and condensate businesses.* We expect that more than 40 percent of our gross operating margin will be derived from the crude oil, condensate and NGL businesses by the fourth quarter of 2013, an increase from 21 percent, 9 percent and 8 percent in 2012, 2011 and 2010, respectively.
- *Evolve into a fee-based provider with projected 2013 gross operating margin from fee-based businesses of over 85 percent, an increase from 83 percent, 70 percent and 77 percent in 2012, 2011 and 2010, respectively*. Our objective has been to focus on long-term contracts that will provide us with sustainable and more predictable cash flow.
- *Expand into new geographic areas beyond our traditional strongholds and enhance our footprint in north Texas, Louisiana and south Louisiana.* We will continue to focus on our activities in the developing Utica Shale play in Ohio, our Cajun-Sibon pipeline extension and our growing business in the Permian Basin in west Texas. By diversifying our geographic focus, we believe we will be less reliant on any individual geographic area or product line.

Recent Growth Developments

Cajun-Sibon Phases I and II. In Louisiana, we are transforming our business that has been historically 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 has historically 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. This is a pivotal asset for Cajun-Sibon Phase I as we are expanding this facility to a rate of 55,000 Bbls/d. When Phase I of our pipeline extension project is completed, Mont Belvieu supply lines in east Texas will be connected to Eunice providing a direct link to our fractionators in south Louisiana markets. The Eunice fractionator expansion will increase our interconnected fractionation capacity in Louisiana to approximately 97,000 Bbls/d of raw-make NGLs.

Construction is underway on Phase I, which includes a 130-mile, 12-inch diameter pipeline extension of our existing 440-mile Cajun-Sibon NGL pipeline system, connecting Mont Belvieu to our Eunice fractionator. The pipeline will have an initial capacity of 70,000 Bbls/d for raw make NGLs. The Phase I NGL pipeline extension will originate from interconnects with major Mont Belvieu supply pipelines, providing connections for NGLs from the Permian Basin, Mid-Continent, Barnett Shale, Eagle Ford, and Rocky Mountain areas to our NGL fractionation facilities and key NGL markets in south Louisiana. We expect Phase I facilities, both the NGL pipeline and the expanded Eunice fractionation facilities, will be operating by mid-2013. Phase I is anchored by a five year ethane sales agreement with Williams Olefins, a subsidiary of the Williams Companies.

Cajun-Sibon Phase II will further enhance our Louisiana NGL business with significant additions to the Cajun-Sibon Phase I NGL pipeline extension and fractionator 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 butanes-and-heavier facility; and the construction of 57 miles of NGL pipelines 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; and ultimately, the construction of 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 have entered into 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 expect Phase II will be in service during the second half of 2014. We currently estimate the total capital investment for both phases of Cajun-Sibon will be between $680.0 million and $700.0 million.

We believe the Cajun-Sibon projects not only represent a tremendous growth step by leveraging our Louisiana assets, but that they also create a significant platform for continued growth of our NGL business. We believe these projects, 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.

Clearfield Acquisition. On July 2, 2012, we completed the acquisition of all of the issued and outstanding common stock of Clearfield Energy, Inc. and its wholly-owned subsidiaries (collectively, "Clearfield"). Clearfield was a crude oil, condensate and water services company with operations in Ohio, Kentucky and West Virginia. We paid approximately $215.0 million in cash for the acquisition, which was funded from the proceeds of our May 2012 offering of 7.125% Senior Notes due 2022. The assets associated with this acquisition are included in a new reporting segment that is referred to as Ohio River Valley.

Our Ohio River Valley assets include a 4,500-barrel-per-hour crude oil barge loading terminal on the Ohio River, a crude rail loading terminal on the Ohio Central Railroad network that is being expanded to a 20-spot operation and approximately 200 miles of crude oil pipelines in Ohio and West Virginia. We also have 500,000 barrels of above ground storage, seven existing brine disposal wells with one under development and a truck fleet of approximately 100 trucks. In addition, we own more than 2,500 miles of unused rights-of-way.

We believe our Ohio River Valley assets provide a first-mover advantage in the developing Utica Shale, in addition to providing access to the Marcellus Shale. We view this position as our next growth platform and it offers us a great opportunity to continue to diversify into the crude and condensate business. From an operations standpoint, we are focusing on improving or expanding the existing assets. We are enhancing our Black Run rail terminal, increasing storage capacity and condensate handling at Bells Run barge terminal on the Ohio River, and expanding the capacity of our brine disposal network and wells. We achieved record brine disposal rates in the fourth quarter, the result of optimizing our newest disposal well in West Virginia along with the six other disposal wells on the system. We have also focused on utilization and deployment of our truck fleet, which we are transitioning to a seven-day, 24-hour operation.

Investment in Limited Liability Company. On June 22, 2011, we entered into a limited liability agreement with HEP for an initial capital contribution of $35.0 million in exchange for an individual ownership interest in HEP. In 2012, we made an additional capital contribution of $52.3 million to HEP related to HEP's acquisition of substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas. HEP owns midstream assets and provides midstream and construction services to Eagle Ford Shale producers. As of December 31, 2012, we owned a 30.6 percent interest in HEP and accounted for this investment under the equity method of accounting. In December 2012, HEP sold its construction services business. In February 2013, HEP announced that it will construct another cryogenic natural gas plant and an import and export logistics railroad hub to service customers in the Eagle Ford Shale play in south Texas. We expect to make an additional capital contribution of approximately $34.0 million during 2013 to fund our portion of these new construction projects. We expect to receive distributions of approximately $10.0 million to 15.0 million from HEP during 2013.

Riverside Crude Facility Expansion. In January 2012, we completed our modifications to the Riverside fractionation facility in south Louisiana to allow 4,500 Bbls/d of crude oil as well as NGLs to be transloaded from rail to barge. In June 2012, we began construction on Phase II to increase our capacity to transload crude oil from rail cars to both barges and pipeline at our Riverside facility from approximately 4,500 Bbls/d of crude oil to approximately 15,000 Bbls/d of crude oil. The Phase II development at the Riverside facility will include new storage tank facilities, upgraded pipeline connections and improved barge delivery capabilities on the Mississippi River. The expansion project is expected to be operational in the second quarter of 2013 at a cost of approximately $16.4 million. We have entered into a long-term agreement which supports the expansion.

Permian Basin Apache Joint Investment. We and Apache Corporation jointly invested $85.0 million in a new-build natural gas processing facility with a capacity of 58 MMcf/d in the Permian Basin in Glasscock County, Texas, which we refer to as our Deadwood plant. We and Apache funded the processing project equally and each hold a 50 percent undivided working interest in the assets. We commenced operation of this facility in February 2012. The project gives us a footprint for growth in the Permian Basin where we will pursue additional business opportunities.

We also purchased and upgraded a nearby rail terminal and fractionator (we refer to this terminal as the Mesquite Terminal) in Midland County at a cost of $23.4 million to serve initially as a rail terminal for the Deadwood plant and third party raw-make NGLs. After the ethane is removed, these NGLs are transported by rail to our Eunice fractionation facility in south Louisiana for fractionation and sales. We own 100 percent of the terminal and fractionator. The Mesquite Terminal began receiving raw-make NGLs in February 2012 from the Deadwood Plant when we commenced its operation and from others via existing NGL pipelines or trucks. We are also transloading crude oil at the facility. This facility provides NGL takeaway for the constrained Permian infrastructure until a long-term pipeline solution becomes available.

Our Assets

North Texas Assets (including Permian Basin Assets). Our gathering systems in north Texas, or NTG, consist of approximately 690 miles of gathering lines that had an average throughput of approximately 810,000 MMBtu/d for the year ended December 31, 2012. Our processing facilities in north Texas include three gas processing plants with total processing throughput that averaged 324,000 MMBtu/d for the year ended December 31, 2012. Our transmission asset, referred to as the North Texas Pipeline, or NTP, is a 140-mile pipeline from an area near Fort Worth, Texas to a point near Paris, Texas and related facilities. The NTP 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, 2012, the average throughput on the NTP was approximately 350,000 MMBtu/d.

During 2011, we expanded our gas gathering system in north Texas with the construction of a $28.3 million, 15-mile pipeline extension to serve major Barnett Shale producers. The project, which is supported by volumetric commitments, commenced operation in March 2011. We added more compression to this gathering system in January 2012 to increase capacity. In March 2011, we also completed construction of a new compressor station at a cost of approximately $15.9 million that increased compression on an existing north Texas gathering line to handle an additional 50 MMcf/d of natural gas. This capacity increase was needed to support a 10-year gathering commitment from a major Barnett Shale producer.

Our North Texas segment also includes our Deadwood natural gas processing plant, and our Mesquite Terminal and fractionator which comprise our Permian Basin assets. The Deadwood processing facility has a total capacity of 58 MMcf/d and total processing throughput that averaged 40,000 MMBtu/d for the year ended December 31, 2012. See "Recent Growth Developments" for a full description of these assets.

LIG Assets. The LIG gathering and transmission pipeline system is comprised of a north and south system and had an average throughput of approximately 783,000 MMbtu/d for the year ended December 31, 2012. 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 248,000 MMBtu/d for the year ended December 31, 2012. 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 3,800 Bbls/d for the year ended December 31, 2012. We also connected the Plaquemine plant to our south Louisiana NGL system in 2012. 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 firm transportation agreements for 345 MMcf/d on the north system with weighted average lives of approximately four and a half 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. See "Item 7—Liquidity and Capital Resources" 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 440 miles of liquids transport lines. Total processing throughput averaged 738,000 MMBtu/d for the year ended December 31, 2012.

- *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 Bakken plays. The Eunice fractionation facility has a capacity of 15,000 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 7,600 Bbls/d of liquids during 2012. We connected the Plaquemine facility

into our PNGL system during 2012. This connection 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 133,000 barrels. The loading facility has the capacity to transload 4,500 Bbls/d of crude oil and NGLs from rail cars to both barges and pipeline. Total volume for fractionated liquids at Riverside averaged 19,200 Bbls/d for the year ended December 31, 2012. See "Recent Growth Developments" for discussion of the expansion at Riverside.

  - *Cajun-Sibon Pipeline System.* Currently, the Cajun-Sibon pipeline system consists of approximately 440 miles of 6" and 8" pipelines with a system capacity of approximately 28,000 Bbls/d. The pipeline transports unfractionated NGLs, referred to as raw make, from the Eunice, Pelican and Blue Water processing plants 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, located outside of Belle Rose, Louisiana, is connected to the Riverside facility and has a total capacity of 3.1 million barrels of underground storage from 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, 2012, the plant processed approximately 377,000 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.

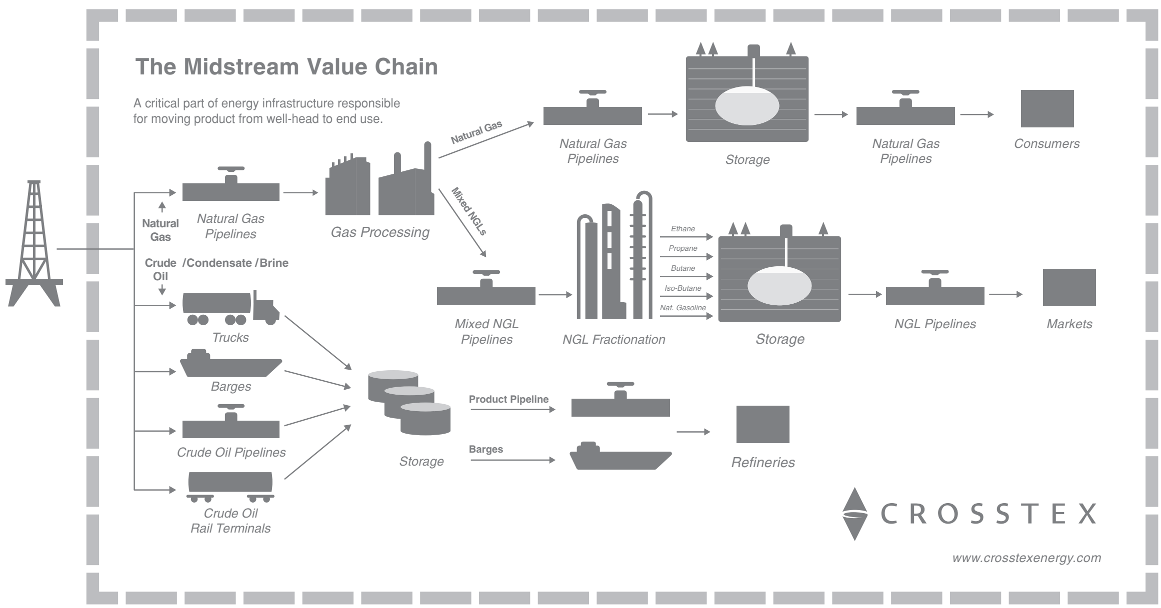
  - *Eunice Processing Plant.* The Eunice processing plant is located in south central Louisiana, has a capacity of 475 MMcf/d and processed approximately 215,000 MMBtu/d for the year ended December 31, 2012. The plant is connected to onshore gas supply as well as continental shelf and deepwater gas production and has downstream connections to the ANR Pipeline, Florida Gas Transmission and Texas Gas Transmission.

  - *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 300 MMcf/d. In January 2009, the flow of the gas on the pipeline was reversed by the Tennessee Gas Pipeline (TGP), the owner of the pipeline, thereby removing access to all the gas processed at our Blue Water plant from the Blue Water offshore system. The gas composition of the reversed TGP stream is leaner in NGL content, but is profitable to process during periods of high fractionation spreads. The plant only operated during the first five months of 2012 and processed approximately 78,000 MMBtu/d for the year ended December 31, 2012. 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 barge loading terminal on the Ohio River, a crude oil rail loading terminal on the Ohio Central Railroad network that is being expanded to a 20-spot operation and approximately 200 miles of crude oil 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 handled averaged approximately 9,800 Bbls/d for the six months operated by us during 2012. We have seven existing brine disposal wells with an injection capacity of approximately 10,000 Bbls/d and an average disposal rate of 7,800 Bbls/d for the six months operated by us during 2012. We currently hold two additional well permits in Ohio, one of which is under development. In addition, we own more than 2,500 miles of unused rights-of-way.

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 and crude oil 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 and crude oil 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 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 terminals. Crude oil rail terminals are an integral part of ensuring the movement of new crude oil production from the developing shale plays in the United States and Canada. In general, the crude oil 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 rail unloading terminals are used to unload rail cars and store crude oil volumes for third parties until the oil is redelivered to premium markets via pipelines, trucks or rail to delivery points.

Balancing Supply and Demand

When we purchase natural gas and crude oil, 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. We currently have not entered into over-the-counter derivative instruments related to our crude oil purchases.

Competition

The business of providing gathering, transmission, processing and marketing services for crude oil, natural gas and NGLs is highly competitive. We face strong competition in obtaining natural gas and crude oil supplies and in the marketing and transportation of crude oil, natural gas and NGLs. Our competitors include major integrated and independent E&P oil companies, natural gas producers, interstate and intrastate pipelines, other natural gas and crude oil 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 and crude oil 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 Supply

Our gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which we believe have ample natural gas supplies in excess of the volumes required for the operation of these systems. 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 to determine the availability of natural gas supply for the systems and/or obtain a minimum volume commitment from the producer that results in a rate of return on investment. Based on these facts, we believe that there should be adequate natural gas supply to recoup our investment with an adequate rate of return. We do not routinely obtain independent evaluations of reserves dedicated to our systems due to the cost and relatively limited benefit of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems 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, 2012, we had only one customer, Dow, which represented greater than 10.0% of our revenue. While this customer represented 10.5% 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

Regulation by FERC of Interstate Natural Gas Pipelines. We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or FERC, does not directly regulate our 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 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.

Regulation by FERC of Interstate Liquids Pipelines. As discussed in "Recent Growth Developments," we acquired liquids transportation, storage and other assets in the Ohio River Valley in 2012, 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. Further, we began construction in 2012 of an expansion of the Cajun-Sibon NGL pipeline that is connected to our fractionation facilities in south Louisiana. This expansion is scheduled to be operational mid-2013. Once operational, the expansion will be 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 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.

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. The price at which we sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our natural gas 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 industry, most notably interstate natural gas transmission companies that remain subject to FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. We cannot predict the ultimate impact of these regulatory changes on our natural gas 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 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 well, 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 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.

We believe our operations are in material compliance with applicable environmental laws and regulations. However, 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.

We believe that we currently hold all material governmental approvals required to operate our major facilities. As part of the regular evaluation of our operations, we routinely review and update governmental approvals as necessary. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations currently in effect will not have a material adverse effect on our operating results or financial condition.

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 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 as 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 we 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 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 1, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. Depending on the outcome of such proceedings, the rules may be 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. 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 has not yet 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.

Water and Hydraulic Fracturing Regulation. 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.

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. The new 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. 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. 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. This sinkhole is situated west of our underground natural gas and NGL storage facility.

Following the formation of the sinkhole, we and other pipeline operators in the area promptly undertook steps to depressurize and shutdown 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 begun work on rerouting this pipeline outside of the affected areas. Bringing this pipeline into operation will be subject to costs, lengthy and detailed planning, right-of-way acquisition and federal and state permitting requirements. We also implemented additional inspection and operational measures, including use restrictions, at our nearby underground facility. The damage to our business, including costs and loss of business, will be 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 2012 and 2013."

The cause and full consequences of this sinkhole and natural gas release 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, 2012, we (through our subsidiaries) employed approximately 736 full-time employees. Approximately 205 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 unit 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 Inherent In Our Business

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, 2012 approximately 7.5% 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 ended December 31, 2012 approximately 9.6% of our total gross operating margin was generated under processing margin contracts. We have a number of processing margin contracts with 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 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.

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, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, prices of natural gas and NGLs in 2012 were below the market prices realized throughout most of 2011 while prices for oil were relatively consistent with 2011 market prices. Crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2012 ranged from a high of $109.77 per Bbl in February 2012 to a low of $77.69 per Bbl in June 2012. Weighted average NGL prices in 2012 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a high of $1.36 per gallon in January 2012 to a low of $0.79 per gallon in June 2012. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2012 ranged from a low of $1.83 per MMBtu in April 2012 to a high of $3.77 per MMBtu in November 2012.

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."

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

We have a substantial amount of indebtedness. As of December 31, 2012, we had approximately $1.04 billion of indebtedness outstanding primarily comprised of $725.0 million (including $9.7 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, 2012, there was $71.0 million of borrowing and $62.2 million in outstanding letters of credit under the bank credit facility leaving approximately $501.8 million available for future borrowings and letters of credit based on a borrowing capacity of $635.0 million. However, the financial covenants in the amended credit facility limit the amount of funds that we can borrow. As of December 31, 2012, based on the financial covenants in the amended credit facility, we could borrow approximately $334.6 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 and NGL services businesses would materially impact our financial condition.

We rely exclusively on the revenues generated from our gathering, transmission, processing, crude oil 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 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 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 NTP and sell the gas into a different market area index. For the year ended December 31, 2012, we have recorded a loss of approximately $17.5 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 2013. 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."

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.

Our gathering systems are connected to wells and our crude oil and condensate assets service wells from which production will naturally decline over time, which means that cash flows associated with these assets will likely also decline over time. 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 supplies. We may not be able to obtain additional contracts for crude oil, condensate and natural gas 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. Natural gas prices were relatively low in 2012 and continue to be depressed. Prolonged periods of low natural gas 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 natural gas available to our systems. 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 construction risks, 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. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed our expectations. 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. In addition, we face the risks of construction delay and additional costs due to obtaining rights-of-way, federal permits, state permits and local permits and complying with federal or state laws and city ordinances.

Our failure to effectively execute our major development projects could result in significant delays and/or 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 Phase I and Phase II of our Cajun-Sibon pipeline expansions. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, 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. 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 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.

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, 2012, 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.

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.

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.

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 and the indentures governing our senior notes contain, 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. These 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 senior secured credit facility, the lenders under our senior secured 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 senior secured credit facility. If indebtedness under our senior secured 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 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 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.

With our acquisition of Clearfield, we entered geographic regions in which we did not previously operate, including Kentucky, Ohio and West Virginia. In order to operate effectively in these new regions, we need to understand the local market and regulatory environment and identify and retain certain employees from Clearfield 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 Clearfield acquisition.

We face new risks as we entered into new lines of business as a result of the Clearfield acquisition.

As a result of the Clearfield acquisition, we entered new lines of business including the transportation of crude oil and condensate by rail cars, barge facilities and trucks and the disposal and transportation of brine. Prior to the Clearfield acquisition, we did not have experience in these lines of business and the success of this acquisition will be subject to all of the uncertainties regarding the maintenance and development of these new lines of business. These activities involve a number of uncertainties, risks and expenses, including the investment of significant time and resources, and we can give no assurance that our efforts will be successful.

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, 2012, approximately 56% 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. Certain agreements with key customers provide for minimum volumes of natural gas 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 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.

Federal, state or local regulatory measures could adversely affect our business.

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.

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. 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.

In 2012, we acquired 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 ICA. Further, the Cajun-Sibon NGL pipeline is scheduled to be operational in mid-2013 and will operate as an interstate, common carrier NGL pipeline subject to FERC's jurisdiction under the ICA.

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.

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.

The states in which we conduct operations administer federal pipeline safety standards under the NGPA. These standards only apply to certain 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 restricted in the future, and they do not apply to our natural gas transmission pipelines. In response to recent pipeline accidents in other parts of the country, Congress and the Department of Transportation, or DOT, have passed or are considering heightened pipeline safety requirements, including gathering lines.

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 $1.4 million, $1.3 million, and $1.4 million for the years ended December 31, 2012, 2011 and 2010, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $2.0 million during 2013. 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, the cost of which cannot be estimated at this time.

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.

Our business involves hazardous substances and may be adversely affected by environmental regulation.

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 became effective 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.

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.

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 and storage of natural gas, NGLs and crude oil, 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; 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.

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.

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 Commodity Futures Trading Commission (the "CFTC") to regulate certain markets for over-the-counter ("OTC") derivative products. 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 to be cleared through clearinghouses. The rules could also impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. 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, including determinations with respect to the applicability of margin requirements and other trading structures, 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.

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, both houses of Congress have actively 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.

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.

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.

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 prohibitions 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.

Risk 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 common 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 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 19.7% fully diluted limited partner interest in us as of December 31, 2012 (17.3% following our January 2013 equity offering). 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, 2012, CEI indirectly owned an aggregate fully diluted limited partner interest of approximately 19.7% in us (17.3% following our January 2013 equity offering). 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 66⅔% of the outstanding units voting together as a single class. Affiliates of the general partner controlled approximately 19.7% of all the limited partner units as December 31, 2012 (17.3% following our January 2013 equity offering).

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. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

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. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income, 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. 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, 2013, 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 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.

We (or our subsidiaries) are defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The 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. 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 14, 2013, the closing market price for the common units was $18.19 per unit and there were approximately 26,442 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)
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
2011:			
Quarter Ended December 31	$17.49	$15.13	$0.32
Quarter Ended September 30	18.20	13.85	0.31
Quarter Ended June 30	19.76	16.33	0.31
Quarter Ended March 31	17.01	14.30	0.29

(a) For each quarter in which a distribution was paid, an identical cash distribution was paid on all outstanding preferred units during 2011 and 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.

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. We have also established a target of achieving a ratio of total debt to adjusted EBITDA of less than 4.0 to 1.0 which we are trying to achieve over the next couple of years. Our ratio of debt to adjusted EBITDA was 4.2 to 1.0 for the year ended December 31, 2012.

Our ability to distribute available cash is contractually restricted by the terms of our credit facility. Our credit facility contains covenants requiring us to maintain certain financial ratios. 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 are convertible 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 are not redeemable but will pay a quarterly distribution that is the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments.

On September 13, 2012, the board of directors of our general partner amended the Partnership Agreement to amend certain terms and conditions of the preferred units, including, among other corresponding modifications, the following amendments:

- *Distributions Paid-In-Kind (PIK)*: for each quarter through the quarter ending December 31, 2013 (the "PIK Period"), we will pay distributions in-kind on the preferred units ("PIK Preferred Units") without penalty and without affecting our ability to pay cash distributions on the common units.
- *PIK Preferred Unit Price*: during the PIK Period, the fixed price used to determine the number of PIK preferred units to be paid instead of cash distributions will be $13.25 per Preferred Unit.
- *Optional Redemption*: the existing right of the holders of preferred units to convert the preferred units into common units was modified so that such right may not be exercised until the earlier of (i) the business day following the record date for the distribution for the quarter ending December 31, 2013 and (ii) February 10, 2014.
- *Mandatory Redemption*: our right to convert the preferred units into common units on January 19, 2013 was modified so that such right may not be exercised until the business day following the distribution for the quarter ending December 31, 2013 (subject to the satisfaction of the existing conditions applicable to such right).

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 acquisition of our ORV assets is included for the year ended December 31, 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,				
	2012	2011	2010	2009	2008
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Midstream	$1,655,851	$2,013,942	$1,792,676	$1,583,551	$3,558,213
Operating costs and expenses:					
Purchased gas, NGLs and crude oil	1,262,093	1,638,777	1,454,376	1,272,329	3,250,427
Operating expenses	130,882	111,778	105,060	110,394	125,754
General and administrative	61,308	52,801	48,414	59,854	68,864
(Gain) loss on sale of property	(342)	264	(13,881)	(666)	(947)
(Gain) loss on derivatives	1,006	7,776	9,100	(2,994)	(8,619)
Impairments	—	—	1,311	2,894	29,373
Depreciation and amortization	162,226	125,284	111,551	119,088	107,521
Total operating costs and expenses	1,617,173	1,936,680	1,715,931	1,560,899	3,572,373
Operating income (loss)	38,678	77,262	76,745	22,652	(14,160)
Other income (expense):					
Interest expense, net	(86,521)	(79,233)	(87,035)	(95,078)	(74,971)
Loss on extinguishment of debt	—	—	(14,713)	(4,669)	—
Equity in earnings of limited liability company	3,250	—	—	—	—
Other income	5,053	707	295	1,400	27,770
Total other expense	(78,218)	(78,526)	(101,453)	(98,347)	(47,201)
Loss from continuing operations before non-controlling interest and income taxes	(39,540)	(1,264)	(24,708)	(75,695)	(61,361)
Income tax provision	(725)	(1,126)	(1,121)	(1,790)	(2,369)
Loss from continuing operations, net of tax	(40,265)	(2,390)	(25,829)	(77,485)	(63,730)
Income (loss) from discontinued operations, net of tax	—	—	—	(1,796)	25,007
Gain from sale of discontinued operations, net of tax	—	—	—	183,747	49,805
Discontinued operations	—	—	—	181,951	74,812

	Crosstex Energy, L.P. Years Ended December 31,				
	2012	2011	2010	2009	2008
	(In thousands, except per unit data)				
Net income (loss)	(40,265)	(2,390)	(25,829)	104,466	11,082
Less: Net income (loss) from continuing operations attributable to the non-controlling interest	(163)	(48)	19	60	311
Net income (loss) attributable to Crosstex Energy, L.P.	$ (40,102)	$ (2,342)	$ (25,848)	$ 104,406	$ 10,771
Preferred interest in net income attributable to Crosstex Energy, L.P.	$ 20,779	$ 18,088	$ 13,750	$ —	$ —
Beneficial conversion feature attributable to preferred units	$ —	$ —	$ 22,279	$ —	$ —
General partner interest in net income (loss)	$ (534)	$ (732)	$ (4,371)	$ (819)	$ 26,415
Limited partners' interest in net income (loss) attributable to Crosstex Energy, L.P.	$ (60,347)	$ (19,698)	$ (57,506)	$ 105,225	$ (15,644)
Loss per unit from continuing operations:					
Basic and diluted common unit	$ (1.01)	$ (0.38)	$ (1.12)	$ (2.18)	$ (4.90)
Senior subordinated unit	$ —	$ —	$ —	$ 8.85	$ 9.44
Distributions declared per limited partner unit	$ 1.32	$ 1.23	$ 0.51	$ —	$ 2.00
Balance Sheet Data (end of period):					
Working capital deficit	$ (18,323)	$ (22,596)	$ (17,640)	$ (50,320)	$ (32,910)
Property and equipment, net	1,471,248	1,241,901	1,215,104	1,279,060	1,527,280
Total assets	2,422,589	1,955,331	1,984,940	2,069,181	2,533,266
Long-term debt (including current maturities)	1,036,305	798,409	718,570	873,702	1,263,706
Capital lease obligations (including current maturities)	25,257	28,367	31,327	23,799	27,896
Partners' equity including non-controlling interest	1,009,081	900,459	976,936	893,282	797,931
Cash Flow Data:					
Net cash flow provided by (used in)(1):					
Operating activities	$ 103,896	$ 143,572	$ 87,187	$ 80,978	$ 173,750
Investing activities	(490,283)	(132,094)	14,638	379,874	(186,810)
Financing activities	362,368	(5,032)	(84,907)	(461,709)	14,554
Non-GAAP Financial Measures:					
Gross operating margin(2)	$ 393,758	$ 375,165	$ 338,300	$ 311,222	$ 307,786
Adjusted EBITDA(3)(5)	$ 214,089	$ 214,028	$ 186,880	$ 158,682	$ 163,394
Operating Data:					
Pipeline throughput (MMBtu/d)	1,943,000	2,037,000	1,971,000	2,040,000	2,002,000
Natural gas processed (MMBtu/d)	1,350,000	1,325,000	1,366,000	1,235,000	1,608,000
NGL Fractionation (Gals/d)	1,359,000	1,109,000	922,000	686,000	956,000
Crude Oil Handling (BBls/d)(4)	11,800	—	—	—	—
Brine Disposal (Bbls/d)(4)	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, non-controlling interest and 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 related to discontinued operations and equity in earnings of limited liability company.

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

(5) Adjusted EBITDA for the years ended December 31, 2009 and 2008 is from continuing operations.

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, non-controlling interest; certain severance and exit expenses; and accrued legal judgment under appeal; less (income) loss from discontinued operations, gain on sale of assets related to discontinued operations, gain on sale of property and equity in earnings 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 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,				
	2012	2011	2010	2009	2008
	(In thousands)				
Net income (loss) attributable to Crosstex Energy, L.P.	$(40,102)	$ (2,342)	$(25,848)	$ 104,406	$ 10,771
Interest expense	86,521	79,233	87,035	95,078	74,971
Depreciation and amortization	162,226	125,284	111,551	119,088	107,521
Equity in earnings of limited liability company	(3,250)	—	—	—	—
Impairment	—	—	1,311	2,894	29,373
Loss on extinguishment of debt	—	—	14,713	4,669	—
(Gain) loss on sale of property	(342)	264	(13,881)	(666)	(947)
Stock-based compensation	9,207	7,308	9,276	8,742	11,243
(Income) loss from discontinued operations, net of tax	—	—	—	1,796	(25,007)
Gain on sale of discontinued operations, net of tax	—	—	—	(183,747)	(49,805)
Other(a)	(171)	4,281	2,723	6,422	5,274
Adjusted EBITDA(b)	$214,089	$214,028	$186,880	$ 158,682	$163,394

(a) Includes financial derivatives marked-to-market; income taxes; transaction costs associated with successful transactions; non-controlling interest; 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 years ended December 31, 2009 and 2008 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,				
	2012	2011	2010	2009	2008
			(In thousands)		
Total gross operating margin	$ 393,758	$ 375,165	$ 338,300	$ 311,222	$ 307,786
Add (deduct):					
Operating expenses	(130,882)	(111,778)	(105,060)	(110,394)	(125,754)
General and administrative expenses	(61,308)	(52,801)	(48,414)	(59,854)	(68,864)
Gain (loss) on sale of property	342	(264)	13,881	666	947
Gain (loss) on derivatives	(1,006)	(7,776)	(9,100)	2,994	8,619
Depreciation, amortization and impairments	(162,226)	(125,284)	(112,862)	(121,982)	(136,894)
Operating income (loss)	$ 38,678	$ 77,262	$ 76,745	$ 22,652	$ (14,160)

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, processing, transmission and marketing to producers of natural gas, natural gas liquids (NGLs) and crude oil. We also provide crude oil, condensate and brine services to producers. Our midstream energy asset network includes approximately 3,500 miles of pipelines, ten 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 and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil 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 and crude oil.

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 $17.5 million during the year ended December 31, 2012 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, 2013. This estimate is based on forward prices, basis spreads and other market assumptions as of December 31, 2012. These assumptions are subject to change if market conditions change during 2013 and actual results under the Delivery Contract in 2013 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.

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

Recent Developments

Cajun-Sibon Phases I and II. In Louisiana, we are transforming our business that has been historically 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 has historically 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. This is a pivotal asset for Cajun-Sibon Phase I as we are expanding this facility to a rate of 55,000 Bbls/d. When Phase I of our pipeline extension project is completed, Mont Belvieu supply lines in east Texas will be connected to Eunice providing a direct link to our fractionators in south Louisiana markets. The Eunice fractionator expansion will increase our interconnected fractionation capacity in Louisiana to approximately 97,000 Bbls/d of raw-make NGLs.

Construction is underway on the Phase I pipeline extension. The pipeline extension between Mont Belvieu and Eunice will have an initial capacity of 70,000 Bbls/d for raw-make NGLs. We expect Phase I facilities, both the pipeline and the expanded fractionation facilities, will be operating by mid-2013.

Cajun-Sibon Phase II will further enhance our Louisiana NGL business with significant additions to the Cajun-Sibon Phase I NGL pipeline extension and Eunice expansion. Under Phase II we will add pumping stations on the Phase I extension to increase its NGL supply capacity from 70,000 Bbls/d to 120,000 Bbls/d, construct a new 100,000 Bbl/d fractionator at the Plaquemine gas processing plant site and extend the Phase I NGL pipeline from Eunice to the new Plaquemine fractionator. We expect Phase II will be in service during the second half of 2014. We currently estimate the total capital investment for both Phases of Cajun-Sibon will be between $680.0 million and $700.0 million.

Clearfield Acquisition. On July 2, 2012, we completed the acquisition of all of the issued and outstanding common stock of Clearfield Energy, Inc. and its wholly-owned subsidiaries (collectively, "Clearfield"). Clearfield was a crude oil, condensate and water services company with operations in Ohio, Kentucky and West Virginia. We paid approximately $215.0 million in cash for Clearfield, which we funded from proceeds of our May 2012 offering of 7.125% Senior Notes due 2022. The assets associated with this acquisition are included in a new reporting segment that is referred to as Ohio River Valley. See "Item 1. Business—Recent Growth Developments" for further details.

2022 Notes. On May 24, 2012, we issued $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022. The interest payments are due semi-annually in arrears in June and December. Net proceeds from the sale of the notes of $245.1 million (net of transaction costs) were used to fund the Clearfield acquisition and for general partnership purposes, including capital expenditures for the Cajun-Sibon NGL pipeline expansion.

Issuance of Common Units. On May 15, 2012, we 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, our general partner made a capital contribution of $3.4 million in connection with the issuance to maintain its general partner interest. The net proceeds from the common units offering were used for general partnership purposes.

On September 14, 2012, we issued 5,660,378 common units representing limited partner interests in the Partnership at a 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 our currently identified projects, including the Cajun-Sibon NGL pipeline expansion, and for general partnership purposes. Our general partner did not make a general partner contribution to maintain its general partner interest in accordance with the September 2012 amendment to the partnership agreement causing our general partner's contribution to be permissive rather than mandatory.

On January 14, 2013, we 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. Concurrent with the public offering, we issued 2,700,000 common units representing limited partner interest in the Partnership at a price of $14.55 per unit for net proceeds of $39.3 million. The net proceeds from both common unit offerings will be used for capital expenditures for currently identified projects, including the Cajun-Sibon NGL pipeline extension, and for general partnership purposes. Our general partner did not make a general partner contribution to maintain its general partner interest in accordance with the September 2012 amendment to the partnership agreement causing our general partner's contribution to be permissive rather than mandatory.

Other Developments. We jointly invested in two other projects during 2011 and 2012. First, we and Apache Corporation jointly invested $85.0 million in the Deadwood natural gas processing facility in the Permian Basin which commenced operation in February 2012. We own a 50% undivided working interest in this facility which is reflected on a consolidated basis. We also invested a total of $85.3 million during 2011 and 2012 for a 30.6% interest in HEP which owns midstream assets and provides midstream services to Eagle Ford Shale producers. We account for this investment under the equity method of accounting. Both of these investments are discussed more fully under "Item 1. Business—Recent Growth Developments."

During 2011, we expanded our gas gathering system in north Texas with the construction of a $28.3 million, 15-mile pipeline extension to serve major Barnett Shale producers. The project, which is supported by volumetric commitments, commenced operation in March 2011. We added more compression to this gathering system in January 2012 to increase capacity. In March 2011, we also completed construction of a new compressor station at a cost of approximately $15.9 million that increased compression on an existing north Texas gathering line to handle an additional 50 MMcf/d of natural gas. This capacity increase was needed to support a 10-year gathering commitment from a major Barnett Shale producer.

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. For the year ended December 31, 2012, approximately 7.5% of our processed gas arrangements, based on gross operating margin, was 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 margins under margin contracts and spot purchases. For the year ended December 31, 2012, approximately 9.6% 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 natural gas and NGLs have been extremely volatile and we expect this volatility to continue. For example, prices of natural gas and NGLs in 2012 were below the market price realized throughout most of 2011 while prices for oil were relatively consistent with 2011 market prices. Crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2012 ranged from a high of $109.77 per Bbl in February 2012 to a low of $77.69 per Bbl in June 2012. Weighted average NGL prices in 2012 (based on the OPIS Napoleonville daily average spot liquids prices) ranged from a high of $1.36 per gallon in January 2012 to a low of $0.79 per gallon in June 2012. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2012 ranged from a low of $1.83 per MMBtu in April 2012 to a high of $3.77 per MMBtu in November 2012.

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 excludes financial and operating data deemed discontinued operations. We manage our operations by focusing on gross operating margin which we define as operating revenue minus cost of purchased gas, NGLs and crude oil as reflected in the table below.

	Years Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
LIG Segment			
Revenues	$ 786.9	$ 939.3	$ 963.0
Purchased gas and NGLs	(678.2)	(809.5)	(845.6)
Total gross operating margin	$ 108.7	$ 129.8	$ 117.4
NTX Segment			
Revenues	$ 365.5	$ 432.6	$ 399.5
Purchased gas and NGLs	(180.1)	(262.7)	(240.1)
Total gross operating margin	$ 185.4	$ 169.9	$ 159.4
PNGL Segment			
Revenues	$ 862.8	$ 910.9	$ 602.6
Purchased gas and NGLs	(788.8)	(835.4)	(541.1)
Total gross operating margin	$ 74.0	$ 75.5	$ 61.5
ORV Segment			
Revenues	$ 108.0	$ —	$ —
Purchased crude oil	(82.3)	—	—
Total gross operating margin	$ 25.7	$ —	$ —
Corporate			
Revenues	$ (467.3)	$ (268.9)	$ (172.4)
Purchased gas, NGLs and crude oil	467.3	268.9	172.4
Total gross operating margin	$ —	$ —	$ —
Total			
Revenues	$ 1,655.9	$ 2,013.9	$ 1,792.7
Purchased gas, NGLs and crude oil	(1,262.1)	(1,638.7)	(1,454.4)
Total gross operating margin	$ 393.8	$ 375.2	$ 338.3
Midstream Volumes:			
LIG			
Gathering and Transportation (MMBtu/d)	783,000	912,000	902,000
Processing (MMBtu/d)	248,000	247,000	283,000
NTX			
Gathering and Transportation (MMBtu/d)	1,160,000	1,125,000	1,069,000
Processing (MMBtu/d)	364,000	249,000	209,000
PNGL			
Processing (MMBtu/d)	738,000	829,000	874,000
NGL Fractionation (Gals/d)	1,359,000	1,109,000	922,000
ORV*			
Crude Oil Handling (Bbls/d)(1)	11,800	—	—
Brine Disposal (Bbls/d)(1)	7,800	—	—

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

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

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 is comprised of the assets from our acquisition of Clearfield Energy, Inc. in July 2012. These assets 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. See "Recent Developments" for further detail on the acquisition and assets.

- 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. Gross operating margin decreased by $7.7 million from our 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 "Changes in Operations During 2012 and 2013."

- 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 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 new 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%. This 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 from Clearfield 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.

Gain/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)	—	—	—
Other	(0.1)	(0.6)	(0.2)	—
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	$75.1	$64.3
Bank credit facility	6.5	5.5
Capitalized interest	(4.0)	(0.9)
Amortization of debt issue costs and notes discount	7.3	8.3
Other	1.6	2.0
Total	$86.5	$79.2

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

Year ended December 31, 2011 Compared to Year ended December 31, 2010

Gross Operating Margin. Gross operating margin was $375.2 million for the year ended December 31, 2011 compared to $338.3 million for the year ended December 31, 2010, an increase of

$36.9 million, or 10.9%. The increase was due to increased throughput on our gathering and transmission systems, as well as favorable NGL markets during 2011. The following provides additional details regarding this change in gross operating margin:

- The LIG segment had a gross operating margin increase of $12.4 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. The strength of the processing environment during 2011 contributed to a gross operating margin increase of $16.6 million. The Gibson and Plaquemine plants were the primary contributors to this gain with a gross operating margin increase of $10.0 million. Other processing activity contributed an additional gross operating margin increase of $6.6 million. The processing gains were partially offset by a decrease in gross operating margin of $4.2 million on the gathering and transportation assets. Gross operating margins on our gathering and transportation assets decreased due to lower margins realized under new contracts and due to the expiration of certain contracts in 2011.

- The NTX segment had a gross operating margin increase of $10.5 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. An increase in throughput volume primarily from the two expansion projects which commenced operations in March 2011 was the main contributor to a gross operating margin increase of $11.4 million on the gathering and transmission assets. The processing plants also had a gross operating margin increase of $3.9 million due to increased supply and the favorable processing environment. These increases were partially offset by an increase in losses of $4.9 million on the Delivery Contract discussed more fully under "Overview".

- The PNGL segment had a gross margin increase of $14.0 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. This was primarily related to the favorable processing and NGL marketing environment. The PNGL processing plants contributed a gross operating margin increase of $9.9 million. NGL fractionation and marketing activity generated a gross operating margin increase of $4.9 million due to the improved marketing environment and volume increases. The Sabine Pass plant had a gross operating margin decline of $0.9 million due to a decrease in volumes from the offshore pipelines that supply the plant.

Operating Expenses. Operating expenses were $111.8 million for the year ended December 31, 2011 compared to $105.1 million for the year ended December 31, 2010, an increase of $6.7 million, or 6.4%. The increase is primarily the result of the following:

- our labor and benefits expense increased by $4.4 million related to an increase in accrued bonuses and employee headcount for activity related to project expansions in the north Texas segment and technical services;

- our bulk chemicals, supplies and service fees expenses increased $0.5 million related to project expansions;

- our other expenses increased by $2.0 million for an accrued legal judgment under appeal;

- our electric utility expenses increased $1.0 million due to an increase in operations at the Eunice processing plant and other north Texas project expansions; and

- our operating expenses decreased by $1.2 million primarily related to periodic testing incurred in 2010.

General and Administrative Expenses. General and administrative expenses were $52.8 million for the year ended December 31, 2011 compared to $48.4 million for the year ended December 31, 2010, an increase of $4.4 million, or 9.1%. The increase is primarily a result of the following:

- our labor and benefits expense increased by $3.2 million primarily related to an increase in accrued bonuses and an increase in employee headcount; and
- we increased our bad debt expense by $1.0 million in 2011 due to uncollectible gathering fees related to a particular customer.

Gain/Loss on Sale of Property. Loss on sale of property was $0.3 million for the year ended December 31, 2011 compared to a gain of $13.9 million for the year ended December 31, 2010. The loss on sale of property for the year ended December 31, 2011 was primarily related to the sale of a minor section of pipeline in Louisiana in September 2011. The gain on sale of property for the year ended December 31, 2010 was related to the sale of our east Texas assets in January 2010.

Gain/Loss on Derivatives. Loss on derivatives was $7.8 million for the year ended December 31, 2011 compared to a loss of $9.1 million for the year ended December 31, 2010. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Years Ended December 31,			
	2011		2010	
(Gain) Loss on Derivatives:	Total	Realized	Total	Realized
Basis swaps	$ 1.4	$1.3	$5.6	$2.3
Processing margin hedges	6.6	5.7	3.5	5.5
Other	(0.2)	—	—	0.1
Net loss on derivatives	$ 7.8	$7.0	$9.1	$7.9

Impairments. During 2010, impairments totaling $1.3 million were taken on excess pipe that was ultimately sold later during 2010. No impairments were recorded in 2011.

Depreciation and Amortization. Depreciation and amortization expenses were $125.3 million for the year ended December 31, 2011 compared to $111.6 million for the year ended December 31, 2010, an increase of $13.7 million, or 12.3%. The increase of $13.7 million includes $13.4 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. In addition, depreciation increased $0.3 million primarily due to an increase of assets placed in service in our north Texas and LIG regions.

Interest Expense. Interest expense was $79.2 million for the year ended December 31, 2011 compared to $87.0 million for the year ended December 31, 2010, a decrease of $7.8 million, or 9.0%. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2011	2010
Senior notes (secured and unsecured)	$64.3	$ 62.5
Paid-in-kind interest on senior secured notes	—	1.4
Bank credit facility	5.5	10.0
Capitalized interest	(0.9)	(0.1)
Mark to market interest rate swaps	—	(22.4)
Realized interest rate swap losses	—	26.5
Amortization of debt issue costs an notes discount	8.3	6.6
Other	2.0	2.5
Total	$79.2	$ 87.0

Loss on Extinguishment of Debt. Loss on extinguishment of debt was $14.7 million for the year ended December 31, 2010. In February 2010, we repaid our prior credit facility and senior secured notes which resulted in make-whole interest payments on our senior secured notes and the write-off of unamortized debt costs totaling $14.7 million.

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 and NGLs. 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.

Goodwill Impairment. In accordance with FASB ASC 350-20-35, we will test goodwill impairment annually starting July 1, 2013, or between annual tests if an event occurs or circumstances that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

Depreciation Expense and Cost Capitalization. Our assets consist primarily of natural gas, NGL 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 $103.9 million, $143.6 million and $87.2 million for the years ended December 31, 2012, 2011 and 2010, respectively. Income before non-cash income and expenses and changes in working capital for 2012, 2011 and 2010 were as follows (in millions):

	Years Ended December 31,		
	2012	2011	2010
Income before non-cash income and expenses	$127.3	$138.9	$61.2
Changes in working capital	(23.4)	4.7	26.0
Total	$103.9	$143.6	$87.2

The primary reason for the decrease in cash flow from income before non-cash income and expenses of $11.6 million from 2011 to 2012 relates to an increase in operating and general and administrative expenses partially offset by an increase in gross operating margin. The primary reason for the increased cash flow from income before non-cash income and expenses of $77.7 million from 2011 to 2010 relates to payments made in 2010 for settlement of interest rate swaps, make-whole payments and PIK notes combined with an increase in 2011 gross operating margin and a decrease in interest expense.

The change in working capital for 2012, 2011 and 2010 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 $490.3 million and $132.1 million for the years ended December 31, 2012 and 2011, respectively, and net cash provided by investing activities was $14.6 million for the year ended December 31, 2010. Cash flows from investing activities for the years ended December 31, 2012, 2011 and 2010 included proceeds from property sales of $11.8 million, $0.5 million and $60.2 million, respectively. 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. The east Texas assets and a non-operational processing plant held in inventory were the primary assets sold in 2010 for $39.8 million and $19.5 million, respectively. Our primary use of cash related to investing activities for the years ended December 31, 2012, 2011 and 2010 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,		
	2012	2011	2010
Growth capital expenditures	$221.2	$ 85.0	$37.4
Acquisition and asset purchases	215.0	—	—
Maintenance capital expenditures	13.6	12.6	10.8
Investment in limited liability company	52.3	35.0	—
Total	$502.1	$132.6	$48.2

See "Overview—Recent Developments" for further discussion related to 2012 acquisition and growth expenditures and our investment in HEP.

Cash Flows from Financing Activities. Net cash provided by financing activities was $362.4 million for the year ended December 31, 2012, and net cash used in financing activities was $5.0 million and $84.9 million for the years ended 2011 and 2010, respectively. Our primary financing activities consist of the following (in millions):

	Years Ended December 31,		
	2012	2011	2010
Net borrowings (repayments) under bank credit facilities	$(14.0)	$85.0	$(529.6)
Senior secured note repayments	—	—	(316.5)
Senior unsecured note borrowings (net of discount on the note)	250.0	—	711.5
Series B secured note repayment	—	(7.1)	(11.0)
Net payments under capital lease obligations	(3.1)	(3.1)	(2.4)
Debt refinancing costs	(7.2)	(4.0)	(28.6)
Proceeds from issuance of Partnership units(1)(2)	236.2	—	120.8

(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, 2012, 2011 and 2010 were as follows (in millions):

	Years ended December 31,		
	2012	**2011**	**2010**
Common units	$76.5	$60.2	$12.8
Preferred units(1)	14.4	17.2	9.9
General partner interest (including incentive distribution rights)	5.8	3.3	0.4
Total	$96.7	$80.7	$23.1

(1) Excludes distributions paid through the issuance of PIK preferred units for third quarter of 2012.

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. We have also established a target of achieving a ratio of total debt to adjusted EBITDA of less than 4.0 to 1.0 which we are trying to achieve over the next couple of years. Our ratio of debt to adjusted EBITDA was 4.2 to 1.0 for the year ended December 31, 2012.

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, 2012, we had approximately $501.8 million of available borrowing capacity under this facility, although our actual borrowing capacity is limited by our financial covenants. Changes in drafts payable for 2012, 2011 and 2010 were as follows (in millions):

	Years Ended December 31,		
	2012	**2011**	**2010**
Increase (decrease) in drafts payable	$(1.9)	$5.9	$(5.1)

Working Capital Deficit. We had a working capital deficit of $18.3 million as of December 31, 2012. 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, 2012 and 2011 are due to the impact of the fluctuations discussed above.

January 2010 Sale of Preferred Units. On January 19, 2010, the Partnership issued approximately $125.0 million of preferred units to an affiliate of Blackstone/GSO Capital Solutions for net proceeds of $120.8 million. The preferred units are not redeemable, but are entitled to a quarterly distribution that will be the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments.

On September 13, 2012, the board of directors of our general partner amended our partnership agreement to amend certain terms and conditions of the preferred units, including, among other corresponding modifications, the following amendments:

- *Distributions Paid-In-Kind (PIK)*: for each quarter through the quarter ending December 31, 2013 (the "PIK Period"), we will pay distributions in-kind on the preferred units ("PIK Preferred Units") without penalty and without affecting our ability to pay cash distributions on the common units.
- *PIK Preferred Unit Price*: during the PIK Period, the fixed price used to determine the number of PIK Preferred Units to be paid instead of cash distributions will increase from $8.50 per preferred unit to $13.25 per preferred unit.
- *Optional Redemption*: the existing right of the holders of preferred units to convert the preferred units into common units 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 was modified so that such right may not be exercised until the earlier of (i) the business day following the record date for the distribution for the quarter ending December 31, 2013 and (ii) February 10, 2014.
- *Mandatory Redemption*: our right to convert the preferred units into common units on January 19, 2013 was modified so that such right may not be exercised until the business day following the distribution for the quarter ending December 31, 2013 (subject to the satisfaction of the existing conditions applicable to such right).

Changes in Operations During 2012 and 2013. 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. 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 the current month-to-month 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 $20.0 million as of December 31, 2012 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.

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 reduced our gross operating margin by approximately $1.2 million per quarter. We are in the process of negotiating 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 these pipelines and our underground storage reservoirs located in Napoleonville, Louisiana. This sinkhole is situated west of our underground natural gas and NGL storage facility. 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 expect that the ongoing overall business impact on the services previously provided by the pipeline, which include gathering, processing, transportation and end-user sales, will be approximately $0.25 to $0.3 million per month while the pipeline section is out of service.

We are working to relocate the portion of the pipeline affected and certain services will not resume until the relocation has been completed. We have evaluated potential rerouting alternatives, timing and expected costs. Based upon the alternative being considered, we estimate the cost of the relocation to be $20.0 to $25.0 million and expect to complete the relocation by summer 2013. We have accelerated the depreciation of this effected portion of the existing pipeline in the amount of $0.4 million and will capitalize the costs of the replacement pipeline.

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 give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

Capital Requirements. Our 2013 capital budget includes approximately $465.0 million of identified growth projects and capital interest. Our primary capital projects for 2013 include the expansion of the Cajun-Sibon NGL Pipeline Phase I and II. During 2012, we invested in several capital projects which included the expansion of the Cajun-Sibon NGL Pipeline and construction of processing plants in the Permian Basin. The Cajun-Sibon NGL pipeline expansion projects have an estimated cost of $680.0 million to $700.0 million. See "Item 1. Business—Recent Growth Developments" for further details.

In 2013, it is possible that not all of the planned projects will be commenced or completed. We expect to fund our maintenance capital expenditures of approximately $13.0 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, proceeds from the sale of the LDCs discussed below and proceeds from other debt and equity sources including our January 2013 offering. 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.

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. On October 15, 2012, a subsidiary of the Partnership entered into an agreement to sell the LDCs for an amount of $19.5 million, and the sale was completed on January 18, 2013. The proceeds from the sale of the LDCs will be used to fund 2013 growth capital expenditures.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2012, 2011 and 2010.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2012 is as follows (in millions):

	Payments Due by Period						
	Total	2013	2014	2015	2016	2017	Thereafter
Long-term debt obligations	$ 975.0	$ —	$ —	$ —	$ —	$ —	$ 975.0
Bank credit facility	71.0	—	—	—	71.0	—	—
Interest payable on fixed long-term debt obligations	522.2	82.2	82.2	82.2	82.2	82.2	111.2
Capital lease obligations	30.4	4.6	4.6	4.6	4.6	6.9	5.1
Operating lease obligations	45.3	8.5	7.6	7.7	7.0	4.3	10.2
Purchase obligations	7.3	7.3	—	—	—	—	—
Additional benefit obligations	4.4	1.0	3.4	—	—	—	—
Inactive easement commitment*	10.0	—	—	—	—	—	10.0
Uncertain tax position obligations	4.1	4.1	—	—	—	—	—
Total contractual obligations	$1,669.7	$107.7	$97.8	$94.5	$164.8	$93.4	$1,111.5

* 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, 2012 our cash obligation for interest expense on our credit facility would be approximately $3.1 million per year.

Indebtedness

As of December 31, 2012 and 2011, long-term debt consisted of the following (in millions):

	2012	2011
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2012 and December 31, 2011 was 4.3% and 2.9%, respectively	$ 71.0	$ 85.0
Senior unsecured notes (due 2018), net of discount of $9.7 million and $11.6 million, respectively, which bear interest at the rate of 8.875%	715.3	713.4
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250.0	—
Debt classified as long-term	$1,036.3	$798.4

Credit Facility. We amended our bank credit facility in January 2012, May 2012, August 2012 and January 2013. Among other things, the amendments contained the following changes:

- Increased borrowing capacity from $485.0 million to $635.0 million;
- Increased the maximum permitted consolidated leverage ratio to 5.5 to 1.0 for each fiscal quarter ending on or prior to December 31, 2013, with a maximum ratio of 5.25 to 1.0 for each fiscal quarter ending thereafter;

- Decreased the minimum permitted interest coverage ratio to 2.25 to 1.0 for each fiscal quarter ending on or prior to December 31, 2013, with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter; and
- Amended the credit facility to include projected EBITDA from material projects in its EBITDA for purposes of calculating compliance with the amended credit agreement's minimum interest coverage ratio, maximum leverage ratio and maximum senior leverage ratio. The aggregate amount of all material project EBITDA adjustments during any period shall be limited to 15% of the total actual consolidated EBITDA for such period.

As of December 31, 2012, there was $71.0 million of outstanding borrowings and $62.2 million in outstanding letters of credit under the amended credit facility leaving approximately $501.8 million available for future borrowings and letters of credit based on a borrowing capacity of $635.0 million. However, the financial covenants in the amended credit facility limit the amount of funds that we can borrow. As of December 31, 2012, based on the financial covenants in the amended credit facility, we could borrow approximately $334.6 million of additional funds.

The 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 credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The 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 credit facility.

Under the amended 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 amended credit facility and a commitment fee of between 0.375% and 0.50% per annum on the unused availability under the amended 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 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 amended 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 maximum permitted leverage ratio (as defined in the 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 1.00 for the fiscal quarters ending on or before December 31, 2013 with a maximum ratio of 5.25 to 1.00 for each fiscal quarter thereafter. The maximum permitted senior leverage ratio (as defined in the 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 minimum consolidated interest coverage ratio (as defined in the 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 1.00 for the fiscal quarters ending on or before December 31, 2013, with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter.

In addition, the 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;
- 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 credit facility permits us to make quarterly distributions to unitholders so long as no default exists under the credit facility.

Each of the following is an event of default under the 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 credit facility).

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

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

We expect to be in compliance with the covenants in the amended credit facility for at least the next twelve months.

Senior Unsecured Notes. On February 10, 2010, we 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). Net proceeds from the sale of the 2018 Notes of $689.7 million (net of transaction costs and OID), together with borrowings under the credit facility discussed above, were used to repay in full amounts outstanding under the prior bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with the prior credit facility. Interest payments on the 2018 Notes are due semi-annually in arrears in February and August.

On May 24, 2012, we 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 are due semi-annually in arrears in June and December. Net proceeds from the sale of the 2022 Notes of $245.1 million (net of transaction costs) were used to fund the Clearfield acquisition and for general partnership purposes, including capital expenditures for the Cajun-Sibon NGLs pipeline expansion.

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 2.00 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 2.00 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.

Prior to February 15, 2014, we may redeem the 2018 Notes, in whole or in part, at a "make-whole" redemption price. 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.

Prior to June 1, 2017, we 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, we 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 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.

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 2010, 2011 and 2012. 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 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.

We (or our subsidiaries) are defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by us as part of its systems. The 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 $2.0 million 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, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations or financial condition.

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 CFTC to regulate certain markets for over-the-counter ("OTC") derivative products. 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 to clear through clearinghouses. The rules could also impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. 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, including determinations with respect to the applicability of margin requirements and other trading structures, 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.

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.

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,		
	2012	2011	2010
Gathering, transportation and crude handling margin	63.8%	56.6%	62.2%
Gas processing margins:			
Processing margin	9.6%	19.3%	12.9%
Percent of liquids	7.5%	10.7%	10.6%
Fee based	19.1%	13.4%	14.3%
Total gas processing	36.2%	43.4%	37.8%
Total	100.0%	100.0%	100.0%

We have hedges in place at December 31, 2012 covering a portion of the liquids volumes we expect to receive under percent of liquids (POL) contracts. The hedges done via swaps are set forth in the following table. The relevant payment index price 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).

Period	Underlying	Notional Volume	We Pay	We Receive*	Fair Value Asset/(Liability)
					(In thousands)
January 2013 - December 2013 .	Ethane	114 (MBbls)	Index	$0.4226/gal	$ 773
January 2013 - December 2013 .	Propane	64 (MBbls)	Index	$1.1713/gal	634
January 2013 - December 2013 .	Normal Butane	34 (MBbls)	Index	$1.7079/gal	108
January 2013 - December 2013 .	Natural Gasoline	23 (MBbls)	Index	$2.2347/gal	140
					$1,655

* weighted average

We have hedged our exposure to declines in prices for NGL volumes produced for our account. The NGL volumes hedged, as set forth above, focus on our POL contracts. We hedge our POL exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total POL volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. We have hedged 47.5% of our hedgeable volumes at risk through December 2013 (34.7% of total volumes at risk through December 2013).

We also have hedges in place at December 31, 2012 covering the fractionation spread risk related to our processing margin contracts as set forth in the following table:

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability)
					(In thousands)
January 2013 - December 2013	Propane	59 (MBbls)	Index	$1.2621/gal*	$ 808
January 2013 - December 2013	Normal Butane	60 (MBbls)	Index	$1.6921/gal*	157
January 2013 - December 2013	Natural Gasoline	34 (MBbls)	Index	$2.2612/gal*	247
January 2013 - December 2013	Natural Gas	2,055 (MMBtu/d)	$3.557/MMBtu*	Index	(21)
					$1,191

* weighted average

In relation to our fractionation spread risk, as set forth above, we have hedged 28.3% of our hedgeable liquids volumes at risk through December 2013 (6.4% of total liquids volumes at risk) and 35.4% of the related hedgeable PTR volumes through December 2013 (7.0% of total PTR volumes).

We are also 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 2.7% 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 the natural gas at a percentage of the 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.

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.

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) our 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, 2012, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $1.9 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $2.0 million in the net fair value asset of these contracts as of December 31, 2012 to a net fair value liability of approximately $0.1 million.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At December 31, 2012, we had $71.0 million outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $0.7 million for the year.

At December 31, 2012 and 2011, we had total fixed rate debt obligations of $965.3 million and $713.4 million, respectively. The balance at December 31, 2012 is related to our 2018 Notes and our 2022 Notes of $715.3 million and $250.0 million with interest rates of 8.875% and 7.125%, respectively. The balance at 2011 is related to our 2018 Notes of $713.4 million with an interest rate of 8.875%. The fair value of these fixed rate obligations was approximately $1.0 billion and $797.5 million as of December 31, 2012 and 2011, respectively. We estimate that a 1% increase or decrease in interest rates would decrease or increase the fair value of the fixed rate debt by $14.7 million based on the debt obligations as of December 31, 2012.

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-37 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, 2012), 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, 2012 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***

None.

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	51	President, Chief Executive Officer and Director
William W. Davis	59	Executive Vice President and Chief Operating Officer
Joe A. Davis	52	Executive Vice President, General Counsel and Secretary
Michael J. Garberding	44	Executive Vice President and Chief Financial Officer
Stan Golemon	49	Senior Vice President-Engineering and Operations
Rhys J. Best**	66	Chairman of the Board and Member of the Conflicts, Finance* and Compensation Committees
Leldon E. Echols**	57	Director and Member of the Audit* and Finance Committees
Bryan H. Lawrence**	70	Director
Sheldon B. Lubar†**	83	Director and Member of the Governance* Committee
Cecil E. Martin**	71	Director and Member of the Audit and Compensation* Committees
D. Dwight Scott**	49	Director and Member of the Compensation and Finance Committee
Kyle D. Vann**	65	Director and Member of the Governance, Conflicts* and Audit Committees

* Denotes chairman of committee.

** Denotes independent director.

† Mr . Lubar resigned in October 2012.

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 IPO 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 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. 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 of 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, 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, 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), Winstar Resources Ltd. (a Canadian public company), 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, a private company that is a middle market credit and asset based investor. 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 Bear Tracker Energy LLC, Energy Alloys LLC and United Engines Holding Company, LLC. 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 to 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. and Legacy Reserves, LLC and on the Advisory Board for Haddington Ventures, LLC. 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, the board of Generous Giving and Mars Hill productions. Mr. Vann's industry experience, and leadership roles in the energy trading and transportation businesses, among other factors, led the Board to conclude that he should serve as a director.

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 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 (and Sheldon Lubar until his resignation in October 2012), 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.

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 web site 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 web site.

Section 16(a)—Beneficial Ownership Reporting Compliance

Based on our records we believe that during 2012 all reporting persons complied with the Section 16(a) filing requirements applicable to them.

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 of directors 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 2012:

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	75%	25%
Michael J. Garberding	75%	25%
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 of Directors 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 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 2012, 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 2012. Meridian's work for the Committee did not raise any conflicts of interest in 2012.

With respect to compensation objectives and decisions regarding the named executive officers for fiscal 2012, 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 2012, 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., Copano Energy, LLC, DCP Midstream Partners, L.P., Eagle Rock Energy Partners, L.P., Magellan Midstream Holdings, L.P., Targa Resources Partners LP, Regency Energy Partners, L.P., MarkWest Energy Partners, L.P., Western Gas Partners, L.P., PVR 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 2012, 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 2012 are shown in the Summary Compensation Table on page 75. Effective January 1, 2013, the base salaries payable to our named executive officers for fiscal 2013 were established as follows: Barry E. Davis $525,000; William W. Davis $395,000; Joe A. Davis $350,000; Michael Garberding $320,000; and Stan Golemon $285,000.

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 2012. Accordingly, the Committee and the Board awarded bonuses to the named executive officers ranging from approximately 30% to 80% of base salary for 2012. 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 2012, our adjusted EBITDA levels for bonuses were $208.0 million for minimum bonuses, $233.0 million for target bonuses and $258.0 million for maximum bonuses. The 2012 plan provided for named executive officers to receive bonus payouts of 10% to 25% of base salary at the minimum threshold, payouts ranging from 50% to 125% of base salary at the target level and payouts ranging from 90% to 225% of base salary at the maximum level. We exceeded our minimum threshold for adjusted EBITDA in 2012.

For 2013, the Board has approved a continuation of the Annual Bonus Plan with adjusted EBITDA as a performance metric. Under the 2013 plan, bonuses will be determined based on adjusted EBITDA levels ranging from a threshold of $220.0 million to a maximum of $250.0 million, with a target adjusted EBITDA of $235.0 million.

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 for employees, consultants, independent contractors and directors of Crosstex Energy GP, LLC and its affiliates 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 covering an aggregate of 5,600,000 common units, which may be awarded in the form of restricted units or unit options. Of the 5,600,000 common units that may be awarded under the long-term incentive plan, 853,777 common units remain eligible for future grants by Crosstex Energy GP, LLC as of January 1, 2013. The long-term compensation structure is intended to align the employee's performance with long-term performance for our unitholders.

The Crosstex Energy GP, LLC Board of Directors in its discretion may terminate or amend the long-term incentive 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 long-term incentive 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 a 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 equal to or more than 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 option plan has 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 Units.* A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. In the future, the Committee may make grants under the plan to employees and directors containing such terms as it shall determine under the plan. The Committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted 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 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 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 units which entitles the grantee to distributions attributable to the restricted units prior to vesting of such units. We intend the issuance of the common units upon vesting of the restricted 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.

- *Performance Units.* A performance unit represents a contractual commitment to grant restricted units in the future if certain conditions are satisfied. In the past performance unit agreements have only been entered into with members of our senior management. We did not grant any performance unit agreements in 2012. Under the terms of past performance unit agreements, to be eligible to receive the restricted units, the executive officer must continuously be employed from the date of the agreement through January 1 of the third calendar year following such date, and no units will be credited to an award recipient under our long term incentive plan until such future date. Each agreement provides for a target number of units that are to be granted in the future. As of January 1, 2013, no performance units granted remain outstanding.

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 2012, Crosstex Energy GP, LLC granted 38,250, 22,950, 18,360, 18,360 and 15,300 restricted units to Barry E. Davis, William W. Davis, Joe A. Davis, Michael J. Garberding and Stan Golemon, respectively. All performance and restricted 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 Plan. The Crosstex Energy, Inc. long-term incentive plans provide for the award of stock options, restricted stock, stock awards and other awards (collectively, "Awards") for up to 7,190,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2013, approximately 1,248,713 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 long-term incentive plan.

The Compensation Committee of Crosstex Energy, Inc.'s board of directors administers the long-term incentive plan. 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 long-term incentive plan terms, conditions, restrictions and limitations. Awards may be granted to employees, consultants and outside directors of Crosstex Energy, Inc.

The Compensation Committee of Crosstex Energy, Inc. 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 Compensation Committee of Crosstex Energy, Inc. 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 Compensation Committee of Crosstex Energy, Inc., 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 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.
- *Restricted Stock Awards.* Restricted stock awards consist of restricted shares of common stock of Crosstex Energy, Inc. The Compensation Committee of Crosstex Energy, Inc. will determine the terms, conditions and limitations applicable to any restricted stock awards. Rights to dividends or dividend equivalents may be extended to and made part of any stock award at the discretion of the Crosstex Energy, Inc. Compensation Committee. Restricted stock awards will have a vesting period established in the sole discretion of the Compensation Committee, provided that the Compensation Committee may provide for earlier vesting by reason of death, disability, retirement or otherwise.
- *Performance Shares.* A performance share represents a contractual commitment to grant restricted shares in the future if certain conditions are satisfied. In the past, performance share agreements have only been entered into with members of our senior management. We did not grant any performance share agreements in 2012. Under the terms of past performance share agreements, to be eligible to receive the restricted shares, the executive officer must continuously be employed from the date of the agreement through January 1 of the third calendar year following such date, and no shares will be credited to an award recipient under our long term incentive plan until such future date. Each agreement provides for a target number of shares that are to be granted in the future. As of January 1, 2013, no performance shares granted remained outstanding.

The Compensation Committee of Crosstex Energy, Inc.'s board of directors may amend, modify, suspend or terminate the long-term incentive plan, 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 Compensation Committee of Crosstex Energy, Inc's. board of directors 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 2012, Crosstex Energy, Inc. granted 50,080, 30,048, 24,038, 24,038 and 20,032 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 2012, 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, for William W. Davis, Joe A. Davis and Michael J. Garberding is two years, and for the other members of senior management is one year with automatic extensions such that the remaining term of the agreements will not be less than one year. The employment agreements include obligations not to disclose confidential information and also provide for a noncompetition 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 or disability, the employment agreement provides that the employee will be paid (i) his or her base salary up to the date of termination, (ii) a pro-rata portion of the target amount of his or her annual bonus up to the date of termination, (iii) an amount equal to the cost to the employee for the premium for health insurance continuation under COBRA for an

18-month period, (iv) 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 (collectively, the "Termination Fee") and (v) a lump sum severance amount equal to one year (two years in the case of the Chief Executive Officer) of the employee's 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.

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 a termination by the Company 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 paid the Termination Fee plus a lump sum severance amount equal to three years of his then current base salary plus three times the target annual bonus for the year of termination, and William W. Davis, Joe A. Davis and Michael J. Garberding would be paid the Termination Fee plus a lump sum severance amount equal to two years of his then current base salary plus two times the target annual bonus for the year of termination.

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 unvested stock or unit awards or restricted stock or units 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 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 Committee.

Upon a change in control, all granted units 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 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, 2012 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. 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	2012	500,000	406,250	1,333,787	—	—	—	257,496(3)	2,497,533
President and Chief Executive	2011	460,000	545,882	1,418,773	—	—	—	195,958	2,620,613
Officer	2010	435,000	427,970	—	—	—	—	71,725	934,695
William W. Davis	2012	385,000	225,225	800,272	—	—	—	185,462(4)	1,595,959
Executive Vice President and	2011	352,692	376,675	917,837	—	—	—	151,644	1,798,848
Chief Operating Officer	2010	330,000	280,315	—	—	—	—	63,083	673,398
Joe A. Davis	2012	335,000	163,313	640,212	—	—	—	156,960(5)	1,295,485
Executive Vice President and	2011	315,000	242,992	620,948	—	—	—	145,004	1,323,944
General Counsel	2010	300,000	254,832	—	—	—	—	62,181	617,013
Michael J. Garberding	2012	290,000	141,375	640,212	—	—	—	138,874(6)	1,210,461
Executive Vice President and	2011	256,538	197,894	848,713	—	—	—	88,124	1,391,269
Chief Financial Officer	2010	225,385	106,084	240,157	—	—	—	31,811	603,437
Stan Golemon	2012	275,000	89,375	533,515	—	—	—	99,281(7)	997,171
Senior Vice President	2011	249,615	124,808	445,253	—	—	—	80,363	900,039
	2010	230,000	111,412	—	—	—	—	32,023	373,435

(1) Bonuses include all payments made under the Annual Bonus Plan. For 2012, the named executive officers received bonuses in the form of stock awards that immediately vest. The amounts shown for 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. with a fair market value of $17.56 per unit and $16.94 per share, respectively. 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 $22,500, distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount $157,448 in 2012, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $75,139 in 2012.

(4) Amount of all other compensation for Mr. William Davis includes professional organization and social club dues, a matching 401(k) contribution of $22,500 distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $109,638 in 2012 and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $50,914 in 2012.

(5) Amount of all other compensation for Mr. Joe Davis includes professional organization and social club dues, a matching 401(k) contribution of $21,519, distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $91,576 in 2012, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $41,456 in 2012.

(6) Amount of all other compensation for Mr. Michael Garberding includes professional organization and social club dues, a matching 401(k) contribution of $17,000, distributions on restricted units of Crosstex Energy, L.P. in the amount of $80,058 in 2012, and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $39,406 in 2012.

(7) Amount of all other compensation for Mr. Stan Golemon includes a matching 401(k) contribution of $15,104, distributions on restricted units of Crosstex Energy, L.P. in the amount of $57,385 in 2012, and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $26,793 in 2012.

Grants of Plan-Based Awards for Fiscal Year 2012 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2012, 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(1)	Grant Date Fair Value of Unit Awards
Barry E. Davis	1/18/2012	38,250	$647,190
William W. Davis	1/18/2012	22,950	$388,314
Joe A. Davis	1/18/2012	18,360	$310,651
Michael J. Garberding	1/18/2012	18,360	$310,651
Stan Golemon	1/18/2012	15,300	$258,876

(1) These grants include Distribution Equivalent Rights (DERs) that provide for distribution on restricted units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2015.

CROSSTEX ENERGY, INC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Number of Shares(1)	Grant Date Fair Value of Shares Awards
Barry E. Davis	1/18/2012	50,080	$686,597
William W. Davis	1/18/2012	30,048	$411,958
Joe A. Davis	1/18/2012	24,038	$329,561
Michael J. Garberding	1/18/2012	24,038	$329,561
Stan Golemon	1/18/2012	20,032	$274,639

(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, 2015.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2012

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2012, 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 (#)(3)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(2)**
Barry E. Davis	—	—	—	—	—	34,722(1) 31,944(3) 15,272(4) 38,250(6)	505,205 464,785 222,208 556,538		
William W. Davis	—	—	—	—	—	30,556(1) 17,969(3) 12,217(4) 22,950(6)	444,590 261,449 177,757 333,923		
Joe A. Davis	—	—	—	—	—	30,556(1) 16,406(3) 4,582(4) 18,360(6)	444,590 238,707 66,668 267,138		
Michael J. Garberding	—	—	—	—	—	9,722(1) 4,142(5) 8,507(3) 18,326(4) 18,360(6)	141,455 60,266 123,777 266,643 267,138	—	—
Stan Golemon	—	—	—	—	—	13,889(1) 8,507(3) 6,109(4) 15,300(6)	202,085 123,777 88,886 222,615	—	—

(1) Restricted units vest on January 1, 2013.

(2) The closing price for the common units was $14.55 as of December 31, 2012.

(3) Restricted units vest on January 1, 2014.

(4) Restricted units vest on August 15, 2014.

(5) Restricted units vest on July 1, 2013.

(6) Restricted units vest on January 1, 2015.

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 . . .	—	—	—	—	—	34,723(1)	497,928		
						51,919(3)	744,518		
						23,148(4)	331,942		
						50,080(6)	718,147		
William W. Davis .	—	—	—	—	—	30,557(1)	438,187		
						29,204(3)	418,785		
						18,519(4)	265,562		
						30,048(6)	430,888		
Joe A. Davis	—	—	—	—	—	30,557(1)	438,187		
						26,665(3)	382,376		
						6,944(4)	99,577		
						24,038(6)	344,705		
Michael J. Garberding	—	—	—	—	—	9,723(1)	139,428	—	—
						5,693(5)	81,638		
						13,826(3)	198,265		
						27,778(4)	398,337		
						24,038(6)	344,705		
Stan Golemon . . .	—	—	—	—	—	13,889(1)	199,168	—	—
						13,826(3)	198,265		
						9,259(4)	132,774		
						20,032(6)	287,259		

(1) Restricted shares vest on January 1, 2013.

(2) The closing price for the common shares was $14.34 as of December 31, 2012.

(3) Restricted shares vest on January 1, 2014.

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

(5) Restricted shares vest on July 1, 2013.

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

Units and Shares Vested Table for Fiscal Year 2012

The following table provides information related to the vesting of restricted units and restricted shares during fiscal year ended 2012.

UNITS AND SHARES VESTED

Name	Crosstex Energy, L.P. Unit Awards		Crosstex Energy, Inc. Share Awards	
	Number of Units Acquired on Vesting	Value Realized on Vesting	Number of Shares Acquired on Vesting	Value Realized on Vesting
Barry E. Davis	34,722	$563,191(1)	34,722	$438,886(2)
William W. Davis	30,555	$495,602(3)	30,555	$386,215(4)
Joe A. Davis	30,555	$495,602(5)	30,555	$386,215(6)
Michael J. Garberding	13,864	$225,620(7)	15,414	$202,574(8)
Stan Golemon	13,889	$225,280(9)	13,889	$175,557(10)

(1) Consists of 34,722 units at $16.22 per unit.

(2) Consists of 34,722 shares $12.64 per share.

(3) Consists of 30,555 units at $16.22 per unit.

(4) Consists of 30,555 shares $12.64 per share.

(5) Consists of 30,555 units at $16.22 per unit.

(6) Consists of 30,555 shares $12.64 per share.

(7) Consists of 9,722 units at $16.22 per unit and 4,142 units at $16.40 per unit.

(8) Consists of 9,722 shares at $12.64 per share and 5,692 shares $14.00 per share.

(9) Consists of 13,889 units at $16.22 per unit.

(10) Consists of 13,889 shares at $12.64 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, 2012.

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*	3,046,565	27,815	—	4,227,815	4,041,286
William W. Davis . . . . . . *Executive Vice President and Chief Operating Officer*	1,124,038	18,038	—	1,874,538	2,771,157
Joe A. Davis . . . . *Executive Vice President and General Counsel*	902,815	27,815	—	1,515,315	2,281,963
Michael J. Garberding . . *Executive Vice President and Chief Financial Officer*	827,815	27,815	—	1,387,815	2,163,555
Stan Golemon . . . . *Senior Vice President*	645,522	18,522	—	645,522	1,454,829

(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 2012.

Compensation of Directors for Fiscal Year 2012

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards(1) ($)	All Other Compensation(2) ($)	Total ($)
Rhys J. Best	234,917	88,879	7,539	331,335
Leldon E. Echols	75,000	69,514	2,827	147,341
Bryan H. Lawrence	—	—	—	—
Sheldon B. Lubar(3)	48,750	69,514	2,827	121,091
Cecil E. Martin	76,125	69,514	2,827	148,466
Kyle D. Vann	199,500	66,655	5,654	271,809
D. Dwight Scott	161,000	—	—	161,000

(1) Messrs. Best, Echols, Lubar, Martin and Vann were granted awards of restricted units of Crosstex Energy, L.P. on May 18, 2012 with a fair market value of $15.18 per unit and that will vest on May 8, 2013 in the following amounts, respectively: 5,855, 2,196, 2,196, 2,196, and 4,391. Messrs. Echols, Lubar, and Martin were granted awards of restricted shares of Crosstex Energy, Inc. on May 18, 2012 with a fair market value of $13.35 per unit and that will vest on May 8, 2013 in the following amounts, respectively: 2,710, 2,710 and 2,710.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, 2012 Messrs. Best, Echols, Martin and Vann held aggregate outstanding restricted unit awards, in the following amounts, respectively: 5,855, 2,196, 2,196, and 4,391. Mr. Lubar forfeited his unvested units and shares when he resigned from the board of directors of Crosstex Energy GP, LLC on October 2, 2012. At December 31, 2012 Messrs. Echols and Martin held aggregate outstanding restricted shares of Crosstex Energy, Inc. in the following amounts, respectively: 2,710 and 2,710. Messrs. Lawrence and Scott held no outstanding restricted unit awards at December 31, 2012.

(2) Other Compensation is comprised of distributions on restricted units.

(3) Mr. Lubar resigned from the board of directors of Crosstex Energy GP, LLC on October 2, 2012.

Each director of Crosstex Energy GP, LLC who is not an employee of Crosstex Energy GP, LLC (other than Mr. Lawrence and Mr. Lubar due to his resignation) is paid an annual retainer fee of $50,000, except for Mr. Best who, as Chairman, is paid an annual retainer fee of $100,000 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—$7,500, Compensation—$7,500, Governance—$5,000, 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 2012. See related party transactions for a discussion of compensation for Mr. Scott.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended 2012, the Committee was composed of Cecil E. Martin, Rhys J. Best and D. Dwight Scott. No member of the Committee during fiscal 2012 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 four meetings during fiscal year 2012. 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 15, 2013, 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.

Percentages reflected in the table are based upon a total of 78,245,974 common units and 15,447,523 Series A Convertible Preferred units as of February 15, 2013.

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	20.98%	—	—	16,414,830	17.52%
GSO Crosstex Holdings, LLC(2)	1,002,800	1.28%	15,447,523	100.00%	16,450,323	17.56%
Kayne Anderson Capital Advisors(3)	8,339,865	10.66%	—	—	8,339,865	8.90%
Barry E. Davis(4)	340,803	*	—	—	340,803	*
William W. Davis(4)	100,423	*	—	—	100,423	*
Joe A. Davis(4)	59,310	*	—	—	59,310	*
Stan Golemon(4)	35,590	*	—	—	35,590	*
Michael J. Garberding(4)	28,460	*	—	—	28,460	*
Rhys J. Best(5)	101,478	*	—	—	101,478	*
Leldon E. Echols(4)	16,957	*	—	—	16,957	*
Bryan H. Lawrence(4)	—	—	—	—	—	—
Cecil E. Martin(4)	25,367	*	—	—	25,367	*
D. Dwight Scott	—	—	—	—	—	—
Kyle D. Vann	70,913	*	—	—	70,913	*
All directors and executive officers as a group (11 persons)	779,301	1.00%	—	—	779,301	0.83%

* 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.

(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 15, 2013, 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 47,558,679 shares of common stock outstanding as of February 15, 2013.

Name of Beneficial Owner(1)	Shares of Common Stock	Percent
GSO Crosstex Holdings, LLC(2)	7,000,000	14.72%
Chickasaw Capital Management, LLC(3)	3,500,725	7.36%
Vanguard Group, Inc.(3)	2,314,487	4.87%
Barry E. Davis	1,681,123	3.53%
William W. Davis	241,144	*
Joe A. Davis	107,393	*
Stan Golemon	34,650	*
Michael J. Garberding	31,352	*
James C. Crain(4)	46,879	*
Leldon E. Echols	19,690	*
Bryan H. Lawrence	1,720,267	3.62%
Cecil E. Martin	9,690	*
Robert F. Murchison(5)	268,731	*
All directors and executive officers as group (10 persons)	4,160,919	8.75%

* 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; Vanguard Group, Inc. which is 100 Vanguard Blvd., Malvem, PA 19355; and Mr. Lawrence, which is 410 Park Avenue, New York, New York 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) 1,000 of these shares are held by the James C. Crain Trust.

(5) 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)	1,352,177(2)	$7.25(3)	853,777
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 2009 for the benefit of our officers, employees and directors. See Item 11, "Executive Compensation—Compensation Discussion and Analysis." The plan, as amended, provides for issuance of a total of 5,600,000 common unit options and restricted units.

(2) The number of securities includes 1,003,159 restricted 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, 2012 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, 23.0% 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") owns 16,414,830 common units, representing approximately 19.7% limited partnership interest in us as of December 31, 2012 and 17.3% following our equity offering in January 2013. 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 2012, this cost reimbursement was approximately $0.07 million per month.

Omnibus Agreement. Concurrent 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 $0.7 million, $0.8 million and $0.8 million during the years ended December 31, 2012, 2011, and 2010, 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.

GSO Crosstex Holdings LLC. GSO Crosstex Holdings LLC owns 15,072,142 Series A Convertible Preferred Units ("preferred units") and 1,002,800 common units representing limited partner interests, representing an approximate 16.9% limited partnership interest in us as of January 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, 2012 and December 31, 2011, review of our internal control procedures for the fiscal year ended December 31, 2012 and December 31, 2011, and the reviews of the financial statements included in our Quarterly Reports on Forms 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 $1.2 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, 2012 and December 31, 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, 2012 and December 31, 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, 2012 and December 31, 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 2013, 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).
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).

Number		Description
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	—	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).
3.9	—	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).
3.10	—	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' 7⅛% 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).

Number		Description
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' 8⅞% 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' 7⅛% 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' 8⅞% 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' 7⅛% 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, dated March 17, 2009 (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, file No. 000-50067).
10.3†	—	Crosstex Energy, Inc. 2009 Long-Term Incentive Plan, effective March 17, 2009 (incorporated by reference to Exhibit 10.3 to Crosstex Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, 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).

Number		Description
10.5†	—	Form of Performance Unit Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007, file No. 000-50067).
10.6†	—	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).
10.7†	—	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 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).
10.9†	—	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).
10.10	—	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).
10.11	—	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).
10.12	—	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).
10.13	—	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).
10.14	—	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).
10.15	—	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).

Number		Description
10.16	—	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).
10.17	—	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).
10.18	—	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).
10.19†	—	Crosstex Energy Services, L.P. Severance Pay Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K July 1, 2011, filed with the Commission on July 1, 2011, file No. 000-50067).
10.20†	—	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).
10.21	—	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).
10.22	—	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).
10.23	—	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.

Number		Description
101**	—	The following financial information from Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010, (ii) Consolidated Balance Sheets as of December 31, 2012 and 2011 , (iii) Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010, (iv) Consolidated Statements of Comprehensive Income for the years ended December 31, 2012, 2011 and 2010, (v) Consolidated Statements of Changes in Partners' Equity for the years ended December 31, 2012, 2011, and 2010 and (vi) the Notes to Consolidated Financial Statements.

* Filed herewith.

** Furnished herewith.

*** In accordance with the instruction on item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibit 2.1 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.

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 1st day of March 2013.

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)	March 1, 2013
/s/ RHYS J. BEST Rhys J. Best	Chairman of the Board	March 1, 2013
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	March 1, 2013
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Director	March 1, 2013
/s/ CECIL E. MARTIN Cecil E. Martin	Director	March 1, 2013
/s/ D. DWIGHT SCOTT D. Dwight Scott	Director	March 1, 2013
/s/ KYLE D. VANN Kyle D. Vann	Director	March 1, 2013
/s/ MICHAEL J. GARBERDING Michael J. Garberding	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 1, 2013

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, 2012, based on criteria established in *Internal Control—Integrated Framework* 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 of December 31, 2012, 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-4 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, 2012 and 2011 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, 2012. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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, 2012 and 2011 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2013, expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
March 1, 2013

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We have audited Crosstex Energy, L.P. and subsidiaries' internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed 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 Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Partnership as of December 31, 2012 and 2011, 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, 2012, and our report dated March 1, 2013 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
March 1, 2013

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets

	December 31, 2012	December 31, 2011
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 124	$ 24,143
Accounts receivable:		
Trade, net of allowance for bad debts of $535 and $405, respectively	63,690	22,680
Accrued revenues	150,734	140,023
Imbalances	1,533	1,658
Other	3,453	1,434
Fair value of derivative assets	3,234	2,867
Natural gas and natural gas liquids inventory, prepaid expenses and other	11,853	9,951
Assets held for disposition	22,599	—
Total current assets	257,220	202,756
Property and equipment:		
Transmission assets	397,381	384,959
Gathering systems	723,626	656,407
Gas plants	586,294	494,365
Other property and equipment	86,838	56,976
Construction in process	180,976	55,467
Total property and equipment	1,975,115	1,648,174
Accumulated depreciation	(503,867)	(406,273)
Total property and equipment, net	1,471,248	1,241,901
Intangible assets, net of accumulated amortization of $263,305 and $199,248, respectively	425,005	451,462
Goodwill	152,627	—
Investment in limited liability company	90,500	35,000
Other assets, net	25,989	24,212
Total assets	$2,422,589	$1,955,331
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 4,093	$ 6,005
Accounts payable	25,839	14,197
Accrued gas and crude oil purchases	140,344	106,232
Accrued imbalances payable	2,333	2,348
Fair value of derivative liabilities	1,310	5,587
Accrued interest	26,712	24,918
Liabilities held for disposition	3,572	—
Other current liabilities	71,340	66,065
Total current liabilities	275,543	225,352
Long-term debt	1,036,305	798,409
Other long-term liabilities	30,256	23,919
Deferred tax liability	71,404	7,192
Commitments and contingencies	—	—
Partners' equity:		
Common unitholders (66,743,632 and 50,676,945 units issued and outstanding at December 31, 2012 and 2011, respectively)	832,529	730,010
Preferred unitholders (15,072,142 and 14,705,882 units issued and outstanding at December 31, 2012 and 2011, respectively)	154,137	147,770
General partner interest (1,553,400 and 1,334,343 equivalent units outstanding at December 31, 2012 and 2011, respectively)	21,784	20,322
Non-controlling interest	—	2,860
Accumulated other comprehensive income (loss)	631	(503)
Total partners' equity	1,009,081	900,459
Total liabilities and partners' equity	$2,422,589	$1,955,331

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Years ended December 31,		
	2012	2011	2010
	(In thousands, except per unit data)		
Revenues:			
Midstream	$1,655,851	$2,013,942	$1,792,676
Total revenues	1,655,851	2,013,942	1,792,676
Operating costs and expenses:			
Purchased gas, NGLs and crude oil	1,262,093	1,638,777	1,454,376
Operating expenses	130,882	111,778	105,060
General and administrative	61,308	52,801	48,414
(Gain) loss on sale of property	(342)	264	(13,881)
Loss on derivatives	1,006	7,776	9,100
Impairments	—	—	1,311
Depreciation and amortization	162,226	125,284	111,551
Total operating costs and expenses	1,617,173	1,936,680	1,715,931
Operating income	38,678	77,262	76,745
Other income (expense):			
Interest expense, net of interest income	(86,521)	(79,233)	(87,035)
Loss on extinguishment of debt	—	—	(14,713)
Equity in earnings of limited liability company	3,250	—	—
Other income	5,053	707	295
Total other expense	(78,218)	(78,526)	(101,453)
Loss before non-controlling interest and income taxes	(39,540)	(1,264)	(24,708)
Income tax provision	(725)	(1,126)	(1,121)
Net loss	$ (40,265)	$ (2,390)	$ (25,829)
Less: Net income (loss) attributable to the noncontrolling interest	(163)	(48)	19
Net loss attributable to Crosstex Energy, L.P.	$ (40,102)	$ (2,342)	$ (25,848)
Preferred interest in net loss attributable to Crosstex Energy, L.P.	$ 20,779	$ 18,088	$ 13,750
Beneficial conversion feature attributable to preferred units	$ —	$ —	$ 22,279
General partner interest in net loss	$ (534)	$ (732)	$ (4,371)
Limited partners' interest in net loss	$ (60,347)	$ (19,698)	$ (57,506)
Net loss per limited partners' unit:			
Basic common unit	$ (1.01)	$ (0.38)	$ (1.12)
Diluted common unit	$ (1.01)	$ (0.38)	$ (1.12)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income (Loss)

	Years Ended December 31,		
	2012	**2011**	**2010**
		(In thousands)	
Net loss	$(40,265)	$(2,390)	$(25,829)
Hedging (gains) losses reclassified to earnings	(689)	1,965	2,085
Adjustment in fair value of derivatives	1,823	(1,609)	(274)
Comprehensive loss	(39,131)	(2,034)	(24,018)
Comprehensive (income) loss attributable to non-controlling interest	163	48	(19)
Comprehensive loss attributable to Crosstex Energy, L.P.	$(38,968)	$(1,986)	$(24,037)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity

Years ended December 31, 2012, 2011 and 2010

	Common Units		Preferred Units		General Partner Interest		Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units			
					(In thousands)				
Balance, December 31, 2009	$873,858	49,163	—	—	18,860	1,003	(2,670)	3,234	893,282
Issuance of preferred units	—	—	120,785	14,706	—	—	—	—	120,785
Beneficial conversion feature attributable to preferred units	(22,279)	—	22,279	—	—	—	—	—	—
Proceeds from exercise of unit options	890	199	—	—	—	—	—	—	890
Conversion of restricted units for common units, net of units withheld for taxes	(2,659)	893	—	—	—	—	—	—	(2,659)
Capital contributions	—	—	—	—	2,807	322	—	—	2,807
Stock-based compensation	5,262	—	—	—	4,014	—	—	—	9,276
Distributions	(12,825)	—	(9,926)	—	(331)	—	—	—	(23,082)
Net income (loss)	(35,227)	—	13,750	—	(4,371)	—	—	19	(25,829)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	2,085	—	2,085
Adjustment in fair value of derivatives	—	—	—	—	—	—	(274)	—	(274)
Distribution to non-controlling interest	—	—	—	—	—	—	—	(345)	(345)
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

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Cash flows from operating activities:			
Net loss	$ (40,265)	$ (2,390)	$ (25,829)
Adjustments to reconcile net loss to net cash provided by operating activities, net of assets acquired or liabilities assumed:			
Depreciation and amortization	162,226	125,284	111,551
Non-cash stock-based compensation	9,207	7,308	9,276
(Gain) loss on sale of property and other assets	(3,328)	264	(13,881)
Impairments	—	—	1,311
Deferred tax benefit	(1,017)	(645)	(396)
Derivatives mark to market interest rate settlement	—	—	(24,160)
Non-cash portion of derivatives (gain) loss	(3,508)	761	1,136
Non-cash portion of loss on debt extinguishment	—	—	5,396
Interest paid-in-kind	—	—	(11,558)
Amortization of debt issue costs	5,377	6,462	6,680
Amortization of discount on notes	1,897	1,897	1,686
Equity in earnings of limited liability company	(3,250)	—	—
Changes in assets and liabilities:			
Accounts receivable, accrued revenue and other	(39,093)	44,225	4,653
Natural gas and natural gas liquids, prepaid expenses and other	(4,016)	(1,532)	2,414
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	19,666	(38,062)	18,908
Net cash provided by operating activities	103,896	143,572	87,187
Cash flows from investing activities:			
Additions to property and equipment	(234,849)	(97,572)	(48,191)
Insurance recoveries on property and equipment	—	—	2,599
Acquisition of business	(214,957)	—	—
Proceeds from sale of property	11,773	478	60,230
Investment in limited liability company	(52,250)	(35,000)	—
Net cash provided by (used in) investing activities	(490,283)	(132,094)	14,638
Cash flows from financing activities:			
Proceeds from borrowings	806,500	471,250	997,412
Payments on borrowings	(570,500)	(393,308)	(1,144,706)
Payments on capital lease obligations	(3,111)	(3,123)	(2,385)
Increase (decrease) in drafts payable	(1,912)	5,854	(5,063)
Debt refinancing costs	(7,155)	(3,954)	(28,561)
Conversion of restricted units, net of units withheld for taxes	(1,030)	(1,798)	(2,659)
Distributions to non-controlling interest	(458)	—	(345)
Distribution to partners	(96,653)	(80,706)	(23,082)
Proceeds from issuance of preferred units	—	—	120,785
Proceeds from exercise of unit options	436	590	890
Net proceeds from common unit offerings	232,791	—	—
Contributions from partners	3,460	163	2,807
Net cash provided by (used in) financing activities	362,368	(5,032)	(84,907)
Net increase (decrease) in cash and cash equivalents	(24,019)	6,446	16,918
Cash and cash equivalents, beginning of period	24,143	17,697	779
Cash and cash equivalents, end of period	$ 124	$ 24,143	$ 17,697
Cash paid for interest	$ 81,237	$ 71,950	$ 66,081
Cash paid for income taxes	$ 1,706	$ 1,104	$ 1,688

See accompanying notes to consolidated financial statements.

(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, NGLs, 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. In addition, we purchase natural gas from producers not connected to our gathering systems for resale and sell natural gas on behalf of producers for a fee. We provide a variety of crude services throughout the Ohio River Valley (ORV) which include crude oil gathering via pipelines 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, 2012, CEI owns 16,414,830 common units in the Partnership through its wholly-owned subsidiaries. As of December 31, 2012, CEI owned 19.7% (17.3% effective following the Partnership's January 2013 offerings) of the limited partner interests in the Partnership and a 1.9% (1.6% effective following the Partnership's January 2013 offering) 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 consolidates 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

(2) Significant Accounting Policies (Continued)

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 and Natural Gas Liquids Inventory

The Partnership's inventories of products consist of natural gas and NGLs. 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 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 $ 4.0 million, $0.9 million and $0.1 million were capitalized for the years ended December 31, 2012, 2011 and 2010, respectively.

Depreciation is provided 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 $98.1 million, $77.8 million and $75.7 million was recorded for the years ended December 31, 2012, 2011 and 2010, respectively. Depreciation expense also includes the amortization of assets classified as capital lease assets.

FASB 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.

(2) Significant Accounting Policies (Continued)

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 and crude oil 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 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

The Partnership has approximately $152.6 million of goodwill at December 31, 2012 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. Goodwill will be assessed at least annually for impairment beginning on July1, 2013.

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, 2012 and 2011 (in thousands):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
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
2011			
Customer relationships	$255,058	$(101,762)	$153,296
Dedicated and non-dedicated acreage	395,652	(97,486)	298,166
Total	$650,710	$(199,248)	$451,462

(2) Significant Accounting Policies (Continued)

The weighted average amortization period for intangible assets is 18.1 years. Amortization expense for intangibles was approximately $64.1 million, $47.5 million and $35.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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

2013	$ 48,156
2014	45,129
2015	43,319
2016	43,429
2017	42,375
Thereafter	202,597
Total	$425,005

(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 2012, the Partnership made an additional capital contribution of $52.3 million to HEP related to HEP's acquisition of substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas. 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. 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 earnings of limited liability company.

(g) Other Assets

Unamortized debt issuance costs totaling $26.0 million and $24.2 million as of December 31, 2012 and 2011, respectively, are included in other assets, net. Debt issuance costs are amortized into interest expense using the straight-line method over the terms 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 $2.3 million and $2.3 million at December 31, 2012 and 2011, respectively, which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $1.5 million and $1.7 million at December 31, 2012 and 2011, respectively, which are carried at the lower of cost or market value.

(2) Significant Accounting Policies (Continued)

(i) Asset Retirement Obligations

FASB ASC 410-20-25-16 was issued in March 2005, which 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 as of December 31, 2012 related to the discontinued use of the Sabine Pass plant. The Partnership did not provide any asset retirement obligations as of 2011 because it did not have sufficient information as set forth in FASB ASC 410-20-25-16 to reasonably estimate such obligations, and the Partnership had no intention of discontinuing use of any significant assets. See Note 2 "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 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 purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. 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) 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.

(2) Significant Accounting Policies (Continued)

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. Realized and unrealized gains and losses on interest rate derivatives that are not designated as hedges are included in interest expense in the consolidated statement of operations. 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, and realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

(l) 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.

(m) 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.

(n) 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, 2012, 2011 and 2010 of $0.5 million, $0.4 million and $0.2 million, respectively.

During the years ended December 31, 2012 and 2011, the Partnership had only one customer that represented greater than 10.0% individually of its revenue. The customer is located in the LIG segment and represented 10.5% and 12.3% of the consolidated revenue for each of the years ended December 31, 2012 and 2011, respectively. During the year ended December 31, 2010, three customers accounted for 14.5%, 10.6%, and 10.2% of consolidated revenue. 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 these customers represent a significant percentage of revenues, the loss of these customers would not have a material adverse impact on the Partnership's results of operations because the gross operating margin received from transactions with these customers are not material to the Partnership's gross operating margin.

(2) Significant Accounting Policies (Continued)

(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, 2012, 2011 and 2010, 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 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,		
	2012	2011	2010
Cost of share-based compensation charged to general and administrative expense	$7,964	$6,157	$7,953
Cost of share-based compensation charged to operating expense	1,243	1,151	1,323
Total amount charged to income	$9,207	$7,308	$9,276

(q) Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the year ended December 31, 2012, 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 Energy, Inc. and Clearfield Energy's wholly owned subsidiaries (collectively, "Clearfield"). Clearfield is a well-established crude oil, condensate and water services company with operations in Ohio, Kentucky and West Virginia. Clearfield's business includes 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.

(3) Acquisition, Disposition and Impairments (Continued)

The Partnership paid approximately $215.0 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 are 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 $19.5 million, and the sale was completed on January 18, 2013. The assets held for disposition net of liabilities assumed are recorded at the sales price of $19.5 million.

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 recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract 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

Based on currently available information, the following table is a summary of the consideration paid for the Clearfield acquisition and the preliminary purchase price allocation for the fair value of

(3) Acquisition, Disposition and Impairments (Continued)

the assets acquired and liabilities assumed at the acquisition date, subject to revision pending finalization of closing adjustments and the sale of the LDC assets:

Purchase Price Allocation (in thousands):	
Purchase Price to Clearfield Energy, Inc.	$214,957
Total purchase price	$214,957
Assets acquired:	
Current assets	$ 17,622
Assets held for disposition	19,500
Property, plant, and equipment	89,752
Goodwill	152,627
Intangibles	37,600
Liabilities assumed:	
Current liabilities	(24,784)
Liabilities held for disposition	(2,627)
Deferred taxes	(65,228)
Long term liabilities	(9,505)
Total purchase price	$214,957

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	$1,761,762	$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)

(3) Acquisition, Disposition and Impairments (Continued)

(b) Other Disposition

The Partnership disposed of assets that were not considered discontinued operations in the year ended December 31, 2010. The 2010 disposition was related to assets in east Texas for a gain of $14.0 million.

(c) Long-Lived Assets Impairments

Impairments of $1.3 million were recorded in the year ended December 31, 2010 related to long-lived assets. The impairment in 2010 primarily relates to the write down of certain excess pipe inventory prior to its sale.

Changes in Operations During 2012 and 2013.

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. 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 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 $20.0 million as of December 31, 2012 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, 2012 and 2011, long-term debt consisted of the following (in thousands):

	2012	2011
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2012 and December 31, 2011 was 4.3% and 2.9%, respectively	$ 71,000	$ 85,000
Senior unsecured notes (due 2018), net of discount of $9.7 million and $11.6 million, respectively, which bear interest at the rate of 8.875%	715,305	713,409
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250,000	—
Debt classified as long-term	$1,036,305	$798,409

(4) Long-Term Debt (Continued)

Maturities. Maturities for the long-term debt as of December 31, 2012 are as follows (in thousands):

2013	—
2014	—
2015	—
2016	$ 71,000
2017	—
Thereafter	975,000
Subtotal	1,046,000
Less discount	(9,695)
Total outstanding debt	$1,036,305

Credit Facility. In January 2012, the Partnership amended its credit facility to increase the Partnership's borrowing capacity from $485.0 million to $635.0 million and amend certain terms under the facility to provide additional financial flexibility during the remaining four-year term of the facility.

The Partnership amended the credit facility again in May 2012. This amendment, among other things, increased the maximum permitted consolidated leverage ratio (as defined in the amended 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) during the Clearfield acquisition period (as defined in the amended credit facility, being generally the four quarterly measurement periods after closing the Clearfield acquisition) from 5.0 to 1.0 to 5.5 to 1.0.

In August 2012, the Partnership amended the credit facility to include projected EBITDA from material projects (as defined in the amendment, but generally being the construction or expansion of any capital project by the Partnership or any of its subsidiaries that is expected to cost more than $20.0 million and the Partnership's "Riverside Phase II" project) in its EBITDA for purposes of calculating compliance with the amended credit agreement's minimum interest coverage ratio, maximum leverage ratio and maximum senior leverage ratio. The amount of projected EBITDA from material projects that is included in such financial covenant calculations is subject to the approval of Bank of America, N.A. (the "Administrative Agent"), and it will be based on contracts related to the material project, expected expenses, the completion percentage of the material project, the expected commercial operation date of the material project, and other factors deemed appropriate by the Administrative Agent. The aggregate amount of all material project EBITDA adjustments during any period shall be limited to 15% of the total actual consolidated EBITDA for such period (which total actual consolidated EBITDA shall be determined without including any material project EBITDA adjustments).

In January 2013, the Partnership amended the credit facility to, among other things, (i) decrease the minimum consolidated interest coverage ratio (as defined in the amended credit agreement, being generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) to 2.25 to 1.0 for the fiscal quarters ending September 30, 2013 and December 31, 2013, with a minimum ratio of 2.50 to 1.0

(4) Long-Term Debt (Continued)

for each fiscal quarter ending thereafter, (ii) increase the maximum permitted consolidated leverage ratio (as defined in the amended credit agreement, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) to 5.50 to 1.0 for each fiscal quarter ending on or prior to December 31, 2013, with a maximum ratio of 5.25 to 1.0 for each fiscal quarter ending thereafter, and (iii) eliminate the existing and any future step-up in the maximum permitted consolidated leverage ratio for acquisitions.

As of December 31, 2012, there was $71.0 million of borrowing and $62.2 million in outstanding letters of credit, under the bank credit facility leaving approximately $501.8 million available for future borrowing based on a borrowing capacity of $635.0 million. However, the financial covenants in the amended credit facility limit the amount of funds that we can borrow. As of December 31, 2012, based on the financial covenants in the amended credit facility, we could borrow approximately $334.6 million of additional funds.

The 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 credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The 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 credit facility.

Under the amended 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 amended credit facility and a commitment fee of between 0.375% and 0.50% per annum on the unused availability under the amended 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 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%

(4) Long-Term Debt (Continued)

The amended 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 maximum permitted leverage ratio (as defined in the 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 1.00 for the fiscal quarters ending on or before December 31, 2013 with a maximum ratio of 5.25 to 1.00 for each fiscal quarter thereafter. The maximum permitted senior leverage ratio (as defined in the 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 minimum consolidated interest coverage ratio (as defined in the 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 1.00 for the fiscal quarters ending on or before December 31, 2013, with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter.

In addition, the credit facility contains various covenants that, among other restrictions, limit the Partnerhship'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 credit facility permits the Partnership to make quarterly distributions to unitholders so long as no default exists under the credit facility.

Each of the following is an event of default under the 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;

(4) Long-Term Debt (Continued)

- 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 credit facility).

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

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

The Partnership expects to be in compliance with the covenants in the 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). Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and OID), together with borrowings under the credit facility discussed above, were used to repay in full amounts outstanding under the prior bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with the prior credit facility. Interest payments on the 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 are due semi-annually in arrears in June and December. Net proceeds from the sale of the notes of $245.1 million (net of transaction costs) were used to fund the Clearfield acquisition and for general partnership purposes, including capital expenditures for the Cajun-Sibon NGLs pipeline expansion.

(4) Long-Term Debt (Continued)

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 2.00 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 2.00 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, 2012.

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 B2 and B+, respectively.

Prior to February 15, 2014, the Partnership may redeem the 2018 Notes, in whole or in part, at a "make-whole" redemption price. 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.

(4) Long-Term Debt (Continued)

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.

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

(4) Long-Term Debt (Continued)

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 and for the years ended December 31, 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, 2012, 2011 and 2010 as these amounts are not considered material.

Condensed Consolidating Balance Sheets
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

December 31, 2011

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
ASSETS				
Total current assets	$ 189,410	$ 13,346	$—	$ 202,756
Property, plant and equipment, net	1,026,537	215,364	—	1,241,901
Total other assets	510,671	3	—	510,674
Total assets	$1,726,618	$228,713	$—	$1,955,331
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 220,811	$ 4,541	$—	$ 225,352
Long-term debt	798,409	—	—	798,409
Other long-term liabilities	31,111	—	—	31,111
Partners' capital	676,287	224,172	—	900,459
Total liabilities & partners' capital	$1,726,618	$228,713	$—	$1,955,331

(4) Long-Term Debt (Continued)

Condensed Consolidating Statements of Operations
For the Year Ended December 31, 2012

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,598,762	$ 84,457	$(27,368)	$ 1,655,851
Total operating costs and expenses	(1,607,359)	(37,182)	27,368	(1,617,173)
Operating income (loss)	(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)

(4) Long-Term Debt (Continued)

For the Year Ended December 31, 2010

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,733,273	$ 84,028	$(24,625)	$ 1,792,676
Total operating costs and expenses	(1,704,250)	(36,306)	24,625	(1,715,931)
Operating income	29,023	47,722	—	76,745
Interest expense, net	(87,029)	(6)	—	(87,035)
Other loss	(14,418)	—	—	(14,418)
Income (loss) before non-controlling interest and income taxes	(72,424)	47,716	—	(24,708)
Income tax provision	(1,110)	(11)	—	(1,121)
Less: Net income attributable to non-controlling interest	—	19	—	19
Net income (loss) attributable to Crosstex Energy, L.P.	$ (73,534)	$ 47,686	$ —	$ (25,848)

Condensed Consolidating Statements of Cash Flow
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)

(4) Long-Term Debt (Continued)

For the Year Ended December 31, 2010

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by operating activities	$ 28,208	$ 58,979	$ —	$ 87,187
Net cash flows provided by (used in) investing activities	$ 21,353	$ (6,715)	$ —	$ 14,638
Net cash flows provided by (used in) financing activities	$(84,907)	$(52,501)	$52,501	$(84,907)

(5) Other Long-Term Liabilities

The Partnership entered into 9 and 10-year capital leases for certain compressor equipment. Assets under capital leases are summarized as follows (in thousands):

	December 31, 2012	December 31, 2011
Compression equipment	$ 37,199	$ 37,199
Less: Accumulated amortization	(13,813)	(10,361)
Net assets under capital lease	$ 23,386	$ 26,838

The following are the minimum lease payments to be made in each of the following years indicated for the capital lease in effect as of December 31, 2012 (in thousands):

Fiscal Year	
2013	$ 4,583
2014	4,582
2015	4,582
2016	4,582
2017	6,910
Thereafter	5,189
Less: Interest	(5,171)
Net minimum lease payments under capital lease	25,257
Less: Current portion of net minimum lease payments	(4,448)
Long-term portion of net minimum lease payments	$20,809

Other long-term liabilities also include an inactive easement commitment of $6.4 million (net of discount of $3.6 million) assumed with the Clearfield acquisition which is due over the next 10 years as such easements are utilized. Also, a long-term liability of $3.0 million was assumed with the Clearfield acquisition for additional benefit obligations from the affiliate of the seller which is payable in monthly installments of $0.08 million over the next 5 years with a contract cancellation option by the affiliate of the seller in July 2014 that would cause the remaining liability to be payable at such time.

(6) 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 $650.3 million as of December 31, 2012. 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 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. The deferred tax liability of $6.6 million attributable to the Clearfield assets that were held for disposition is reflected in current liabilities as of December 31, 2012. The remaining long-term deferred tax liability 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,		
	2012	2011	2010
Current tax provision	$ 1,742	$1,771	$1,517
Deferred tax (benefit)	(1,017)	(645)	(396)
Tax provision	$ 725	$1,126	$1,121

A reconciliation of the provision for income taxes is as follows (in thousands):

	Years Ended December 31,		
	2012	2011	2010
Federal income tax on taxable corporation at statutory rate (35%)	$241	$ 199	$ 43
State income taxes, net	484	927	1,078
Income tax provision	$725	$1,126	$1,121

(6) Income Taxes (Continued)

The principal component of the Partnership's net deferred tax liability is as follows (in thousands):

	Years Ended December 31,	
	2012	2011
Deferred income tax assets—long-term:		
Accrued expenses	$ 1,455	$ —
Deferred transaction cost	863	—
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets-current	$ (7,075)	$ (501)
Property, plant, equipment, and intangible assets-long-term	(73,722)	(7,192)
Net deferred tax liability	$(78,479)	$(7,693)

A net current deferred tax liability of $7.1 million is included in other current liabilities.

A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (in thousands):

Balance as of December 31, 2010	$3,704
Decreases related to prior year tax positions	(8)
Increases related to current year tax positions	517
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

The $0.6 million decrease in prior year tax position mainly consists of unrecognized tax benefits at December 31, 2011 that were recognized in 2012. This benefit was recognized due to the statute of limitations expiring for the applicable tax year. Unrecognized tax benefits as of December 31, 2012 of $4.1 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 2012. 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, 2012, tax years 2009 through 2012 remain subject to examination by the Internal Revenue Service and tax years 2008 through 2012 remain subject to examination by various state taxing authorities.

(7) 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

(7) Partners' Capital (Continued)

proceeds of $120.8 million. The Partnership's general partner made a contribution of $2.6 million in connection with the issuance to maintain its then 2% general partner interest. The 14,705,882 preferred units are 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 Partnership has the right to force conversion of the preferred units beginning on the business day following the distribution for the quarter ended December 31, 2013 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 daily trading volume of common units must exceed 250,000 common units 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. The preferred units are not redeemable, but are entitled to a quarterly distribution that will be 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. During 2012 and 2011, the Partnership paid cash distributions on its preferred units of $14.4 million and $17.2 million, respectively. The distribution for the three months ended September 30, 2012 was paid-in-kind through the issuance of 366,260 preferred units. A distribution on the preferred units of $0.33 per unit was declared for the three months ended December 31, 2012 and was paid-in-kind.

On September 13, 2012, the board of directors of the general partner amended the Partnership Agreement to amend certain terms and conditions of the preferred units including, among other corresponding modifications, the following amendments:

- *Distributions Paid-In-Kind (PIK)*: for each quarter through the quarter ending December 31, 2013 (the "PIK Period"), the Partnership will pay distributions in-kind on the Preferred Units ("PIK preferred units") without penalty and without affecting the Partnership's ability to pay cash distributions on the common units.

- *PIK Preferred Unit Price*: during the PIK Period, the fixed price used to determine the number of PIK preferred units to be paid instead of cash distributions will increase from $8.50 per preferred unit to $13.25 per preferred unit.

- *Optional Redemption*: the existing right of the holders of preferred units to convert the preferred units into common units was modified so that such right may not be exercised until the earlier of (i) the business day following the record date for the distribution for the quarter ending December 31, 2013 and (ii) February 10, 2014.

- *Mandatory Redemption*: the right of the Partnership to convert the preferred units into common units on January 19, 2013 was modified so that such right may not be exercised until the business day following the distribution for the quarter ending December 31, 2013 (subject to the satisfaction of the existing conditions applicable to such right).

The preferred units issued in 2010 were issued at a discount to the market price of the common units they are convertible into. This discount totaling $22.3 million represents a beneficial conversion feature (BCF) and is reflected as a reduction in common unit equity and an increase in preferred equity to reflect the market value of the preferred units at issuance on the Partnership's consolidated statement of changes in partners' equity for the year ended December 31, 2010. The impact of the BCF is also included in earnings per unit for the year ended December 31, 2010.

(7) Partners' Capital (Continued)

(b) Issuance of Common Units

On May 15, 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 capital 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.

On September 14, 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.

On January 14, 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. Concurrent with the public offering, 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 will be 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 this offering.

(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 paid-in-kind 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 to 13% 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 $4.5 million, $2.4 million, and

(7) Partners' Capital (Continued)

$0.1 million were earned by our general partner for the years ended December 31, 2012, 2011 and 2010, respectively. The Partnership paid annual distributions per common unit of $1.31, $1.17 and $0.25 in the years ended December 31, 2012, 2011 and 2010, respectively.

The Partnership's fourth quarter distribution on its common units is $0.33 per unit which was paid February 14, 2013.

(d) Earnings per Unit and Dilution Computations

The Partnership had common units and preferred units outstanding during the year ended December 31, 2012, December 31, 2011 and December 31, 2010.

The preferred units are entitled to a paid-in-kind 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, income allocation is based on the fair value of the PIK Preferred Unit 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

(7) Partners' Capital (Continued)

of basic earnings per limited partner units for the periods presented (in thousands except per unit amounts):

	Years Ended December 31,		
	2012	2011	2010
Limited partners' interest in net loss	$ (60,347)	$(19,698)	$(57,506)
Distributed earnings allocated to:			
Common units(1)	$ 77,794	$ 62,238	$ 25,606
Unvested restricted units	1,306	1,187	545
Total distributed earnings	$ 79,100	$ 63,425	$ 26,151
Undistributed earnings allocated to:			
Common units(2)	$(137,144)	$(81,616)	$(81,703)
Unvested restricted units(2)	(2,303)	(1,507)	(1,954)
Total undistributed earnings (loss)	$(139,447)	$(83,123)	$(83,657)
Net loss allocated to:			
Common units	$ (59,350)	$(19,377)	$(56,097)
Unvested restricted units	(997)	(321)	(1,409)
Total limited partners' interest in net loss	$ (60,347)	$(19,698)	$(57,506)
Total basic and diluted net loss per unit:			
Basic common unit	$ (1.01)	$ (0.38)	$ (1.12)
Diluted common units	$ (1.01)	$ (0.38)	$ (1.12)

(1) Represents distributions declared to common and subordinated unitholders.

(2) All undistributed earnings and losses are allocated to common units and unvested restricted units during the subordination period.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Years Ended December 31,		
	2012	2011	2010
Basic and diluted earnings per unit:			
Weighted average limited partner common units outstanding	58,935	50,590	49,960

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, 2012, 2011 and 2010 because the limited partners were allocated a net loss in these periods.

(7) Partners' Capital (Continued)

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,		
	2012	2011	2010
Income allocation for incentive distributions	$ 4,489	$ 2,372	$ 99
Stock-based compensation attributable to CEI's stock options and restricted shares	(4,205)	(3,119)	(3,906)
General partner interest in net income (loss)	(818)	15	(564)
General partner share of net loss	$ (534)	$ (732)	$(4,371)

(8) Retirement Plans

The Partnership sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The plan allows for contributions to be made at each compensation calculation period based on the annual discretionary contribution rate. Contributions of $3.3 million, $2.5 million and $2.3 million were made to the plan for the years ended December 31, 2012, 2011 and 2010, respectively.

(9) 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 plan currently permits the grant of awards covering an aggregate of 5,600,000 common unit options and restricted units. The plan is administered by the compensation committee of the Partnership's managing general partner's board of directors. The units issued upon exercise or vesting are newly issued units.

(b) Restricted Units

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the restricted units will become exercisable upon a change of control of the Partnership or its general partner.

(9) Employee Incentive Plans (Continued)

The restricted 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 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 units are forfeited. The restricted units granted in 2012, 2011 and 2010 generally cliff vest after three years of service.

The restricted 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 unit activity for the year ended December 31, 2012 is provided below:

Crosstex Energy, L.P. Restricted Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	949,844	$10.45
Granted	417,677	16.58
Vested*	(264,632)	7.93
Forfeited	(99,730)	14.01
Non-vested, end of period	1,003,159	$13.31
Aggregate intrinsic value, end of period (in thousands)	$ 14,596	

* Vested units include 66,180 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted 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, 2012, 2011 and 2010 are provided below (in thousands):

Crosstex Energy, L.P. Restricted Units:	Years Ended December 31, 2012	2011	2010
Aggregate intrinsic value of units vested	$3,850	$6,438	$11,076
Fair value of units vested	$2,097	$5,945	$ 5,785

As of December 31, 2012, there was $5.4 million of unrecognized compensation cost related to non-vested restricted 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 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.

(9) Employee Incentive Plans (Continued)

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, 2012, 2011, and 2010 is provided below:

	Years Ended December 31,					
	2012		2011		2010	
	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	451,574	$ 6.99	611,311	$ 6.77	882,836	$6.43
Exercised	(87,857)	4.96	(128,477)	4.61	(198,725)	4.48
Forfeited	(14,699)	13.39	(31,260)	12.83	(67,183)	9.27
Expired	—	—	—	—	(5,617)	5.37
Outstanding, end of period	349,018	$ 7.25	451,574	$ 6.99	611,311	$6.77
Options exercisable at end of period	286,715	$ 7.52	315,742	$ 7.42	278,214	$7.78
Weighted average contractual term (years) end of period:						
Options outstanding	6.1	—	7.2	—	8.2	—
Options exercisable	6.0	—	6.9	—	7.6	—
Aggregate intrinsic value end of period (in thousands):						
Options outstanding	$ 3,016	—	$ 4,648	—	$ 5,350	—
Options exercisable	$ 2,483	—	$ 3,260	—	$ 2,463	—

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

(9) Employee Incentive Plans (Continued)

date of grant) during the years ended December 31, 2012, 2011 and 2010 is provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options:	**2012**	**2011**	**2010**
Intrinsic value of units options exercised	$988	$1,527	$1,470
Fair value of unit options vested	$277	$ 563	$ 764

As of December 31, 2012, there was less than $0.1 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized during the first quarter of 2013.

(d) Crosstex Energy, Inc.'s Restricted Stock

The Crosstex Energy, Inc. long-term incentive plan provides for the award of restricted stock (collectively, "Awards") for up to 7,190,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2013, approximately 1,248,713 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 2012, 2011 and 2010 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, 2012, is provided below:

Crosstex Energy, Inc. Restricted Shares:	**Number of Shares**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,221,351	$ 7.40
Granted	528,946	13.34
Vested*	(285,872)	6.13
Forfeited	(135,263)	10.27
Non-vested, end of period	1,329,162	$ 9.75
Aggregate intrinsic value, end of period (in thousands)	$ 19,060	

* Vested units include 66,106 units withheld for payroll taxes paid on behalf of employees.

(9) Employee Incentive Plans (Continued)

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, 2012, 2011 and 2010 is provided below (in thousands):

Crosstex Energy, Inc. Restricted Shares:	Years Ended December 31, 2012	2011	2010
Aggregate intrinsic value of shares vested	$4,099	$3,915	$3,163
Fair value of shares vested	$1,754	$5,623	$4,388

As of December 31, 2012 there was $5.5 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 1.2 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, 2012, 2011 and 2010 is provided below:

	Years Ended December 31,					
	2012		2011		2010	
	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	67,500	$ 9.54
Forfeited	—	—	—	—	(30,000)	13.33
Outstanding, end of period	37,500	$6.50	37,500	$6.50	37,500	$ 6.50
Options exercisable at end of period	37,500	$6.50	37,500	$6.50	37,500	$ 6.50

No share options were exercised or vested during the years ended December 31, 2012, 2011 and 2010.

(10) Derivatives

Interest Rate Swaps

The Partnership did not have any interest rate swaps during the years ended December 31, 2012 and December 31, 2011.

(10) Derivatives (Continued)

The impact of the interest rate swaps on net income during the year ended December 31, 2010 is included in other income (expense) in the consolidated statements of operations as part of interest expense, net, as follows (in thousands):

	Year Ended December 31, 2010
Change in fair value of derivatives that do not qualify for hedge accounting	$ 22,405
Realized losses on derivatives	(26,542)
Loss on interest rate swaps	$ (4,137)

Commodity Swaps

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge prices 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 percent of liquids (POL) contracts. 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.

(10) Derivatives (Continued)

The components of loss on derivatives in the consolidated statements of operations relating to commodity swaps are (in thousands):

	Years Ended December 31,		
	2012	2011	2010
Change in fair value of derivatives that do not qualify for hedge accounting	$(3,473)	$ 726	$1,003
Realized losses on derivatives	4,514	7,015	7,955
Ineffective portion of derivatives qualifying for hedge accounting	(35)	(158)	142
Net losses related to commodity swaps	$ 1,006	$7,583	$9,100
Put option premium mark to market	—	193	—
Losses on derivatives	$ 1,006	$7,776	$9,100

The fair value of derivative assets and liabilities relating to commodity swaps are as follows (in thousands):

	December 31,	
	2012	2011
Fair value of derivative assets—current, designated	$ 724	$ 151
Fair value of derivative assets—current, non-designated	2,510	2,716
Fair value of derivative liabilities—current, designated	(105)	(702)
Fair value of derivative liabilities—current, non-designated	(1,205)	(4,885)
Net fair value of derivatives	$ 1,924	$(2,720)

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, 2012 (all gas volumes are expressed in MMBtus and liquids volumes are expressed in gallons). The remaining term of the contracts extend no later than December 2013. Changes in the fair value of the Partnership's mark to market derivatives are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other

(10) Derivatives (Continued)

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, 2012 Volume	December 31, 2012 Fair Value
	(In thousands)	
*Cash Flow Hedges:**		
Liquids swaps (short contracts)	(5,496)	$ 619
Total swaps designated as cash flow hedges		$ 619
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	890	$ (2)
Physical offsets to swing swap transactions (short contracts)	(890)	—
Basis swaps (long contracts)	2,450	13
Physical offsets to basis swap transactions (short contracts)	(2,450)	7,179
Basis swaps (short contracts)	(2,450)	5
Physical offsets to basis swap transactions (long contracts)	2,450	(8,029)
Third-party on-system swaps (long contracts)	465	(19)
Physical offsets to third-party on-system swap transactions (short contracts)	(465)	33
Processing margin hedges—liquids (short contracts)	(6,423)	1,212
Processing margin hedges—gas (long contracts)	750	(21)
Liquids swaps—non-designated (short contracts)	(4,393)	1,035
Storage swap transactions (short contracts)	(2,400)	(101)
Total mark to market derivatives		$ 1,305

* All are gas contracts, volume in MMBtus, except for liquids swaps (designated or non-designated) and processing margin hedges—liquids (volume in gallons).

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 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, 2012 of $3.2 million would be reduced to $2.8 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(10) Derivatives (Continued)

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	2012	2011	2010
Liquids	$1,381	$(2,772)	$(1,733)

Natural Gas

As of December 31, 2012, the Partnership has no balances in accumulated other comprehensive income (loss) related to natural gas.

Liquids

As of December 31, 2012, an unrealized derivative fair value net gain of $0.6 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this net amount, a $0.6 million gain is expected to be reclassified into earnings through December 2013. 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 (gain) loss on derivatives in the consolidated statement of operations. The Partnership estimates the fair value of all of its energy trading contracts using actively quoted prices. The estimated fair value of energy trading 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, 2012	$1,305	$—	$—	$1,305

(11) 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,	
	2012	2011
	Level 2	Level 2
Commodity Swaps*	$1,924	$(2,720)
Total	$1,924	$(2,720)

* 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

(11) Fair Value Measurements (Continued)

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, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$1,036,305	$1,118,875	$798,409	$882,500
Obligations under capital lease	25,257	27,667	28,367	27,637

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 $71.0 million in borrowings under its revolving credit facility included in long-term debt as of December 31, 2012 and $85.0 million in borrowings under this credit facility as of December 31, 2011. 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, 2012 and December 31, 2011, the Partnership also had borrowings totaling $715.3 million and $713.4 million, net of discount, respectively, under the 2018 Notes with a fixed rate of 8.875% and borrowings of $250.0 million as of December 31, 2012 under the 2022 Notes with a fixed rate of 7.125%. The fair value of all senior unsecured notes as of December 31, 2012 and December 31, 2011 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.

(12) Transactions with Related Parties

CEI paid the Partnership $0.7 million, $0.8 million and $0.8 million during the years ended December 31, 2012, 2011 and 2010, 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.

(13) Commitments and Contingencies

(a) Leases—Lessee

The Partnership has operating leases for office space, office and field equipment.

(13) Commitments and Contingencies (Continued)

The following table summarizes the Partnership remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in thousands):

2013	$ 8,512
2014	7,604
2015	7,678
2016	7,068
2017	4,310
Thereafter	10,170
	$45,342

Operating lease rental expense in the years ended December 31, 2012, 2011 and 2010 was approximately $23.2 million, $21.9 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 in 2013. 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.

(13) Commitments and Contingencies (Continued)

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.

The Partnership (or its subsidiaries) is defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The 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. The Partnership has appealed the matter and has posted a bond to secure the judgment pending its resolution. The Partnership has accrued $2.0 million 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.

(14) 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 2011 and 2010 includes the operating activity for intersegment eliminations.

(14) Segment Information (Continued)

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, 2012:						
Sales to external customers	$ 561,389	$ 269,302	$ 717,123	$108,037	$ —	$ 1,655,851
Sales to affiliates	225,542	96,177	145,569	—	(467,288)	—
Purchased gas, NGLs and crude oil	(678,188)	(180,116)	(788,803)	(82,274)	467,288	(1,262,093)
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 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
Gain (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
Year Ended December 31, 2010						
Sales to external customers	$ 880,336	$ 309,771	$ 602,569	$ —	$ —	$ 1,792,676
Sales to affiliates	82,688	89,752	—	—	(172,440)	—
Purchased gas, NGLs and crude oil	(845,627)	(240,085)	(541,104)	—	172,440	(1,454,376)
Operating expenses	(33,188)	(46,384)	(25,488)	—	—	(105,060)
Segment profit	$ 84,209	$ 113,054	$ 35,977	$ —	$ —	$ 233,240
Loss on derivatives	$ (3,664)	$ (5,352)	$ (84)	$ —	$ —	$ (9,100)
Depreciation, amortization and impairments	$ (12,308)	$ (64,458)	$ (31,661)	$ —	$ (4,435)	$ (112,862)
Capital expenditures	$ 9,930	$ 31,678	$ 5,871	$ —	$ 1,907	$ 49,386
Identifiable assets	$ 330,199	$1,107,279	$ 493,143	$ —	$ 54,319	$ 1,984,940

(14) Segment Information (Continued)

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,		
	2012	2011	2010
Segment profits	$ 262,876	$ 263,387	$ 233,240
General and administrative expenses	(61,308)	(52,801)	(48,414)
Gain (loss) on derivatives	(1,006)	(7,776)	(9,100)
Gain (loss) on sale of property	342	(264)	13,881
Depreciation, amortization and impairments	(162,226)	(125,284)	(112,862)
Operating income	$ 38,678	$ 77,262	$ 76,745

(15) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
2012:					
Revenues	$371,709	$351,194	$406,968	$525,980	$1,655,851
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 loss attributable to Crosstex Energy, L.P.	$ 4,853	$ 4,853	$ 5,640	$ 5,433	$ 20,779
General partner interest in net loss	$ (71)	$ (40)	$ (309)	$ (114)	$ (534)
Limited partners' interest in net 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)
2011:					
Revenues	$489,770	$525,735	$517,498	$480,939	$2,013,942
Operating income	$ 19,983	$ 22,890	$ 16,249	$ 18,140	$ 77,262
Net income (loss) attributable to the non-controlling interest	$ (54)	$ (52)	$ (23)	$ 81	$ (48)
Net income (loss) attributable to the Crosstex Energy, L.P.	$ 128	$ 1,667	$ (2,736)	$ (1,401)	$ (2,342)
Preferred interest in net income (loss) attributable to Crosstex Energy, L.P.	$ 4,265	$ 4,559	$ 4,558	$ 4,706	$ 18,088
General partner interest in net loss	$ (522)	$ (111)	$ (76)	$ (23)	$ (732)
Limited partners' interest in net loss attributable to Crosstex Energy, L.P.	$ (3,615)	$ (2,781)	$ (7,218)	$ (6,084)	$ (19,698)
Loss per limited partner unit-basic	$ (0.07)	$ (0.05)	$ (0.14)	$ (0.12)	$ (0.38)
Loss per limited partner unit-diluted	$ (0.07)	$ (0.05)	$ (0.14)	$ (0.12)	$ (0.38)

EXHIBIT 12.1

RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Earnings Before Fixed charges:			
Earnings from continuing operations before non-controlling interest or tax	$(39,540)	$(1,264)	$(24,708)
Capitalized interest	(4,048)	(900)	(128)
Depreciation of capitalized interest	992	790	745
Non-controlling interest	(163)	(48)	19
Total earnings before fixed charges	$(42,759)	$(1,422)	$(24,072)
Fixed charges:			
Interest expense includes discontinued operations	$ 86,521	79,233	87,035
Capitalized interest includes discontinued operations	4,048	900	128
Total fixed charges	$ 90,569	$80,133	$ 87,163
Total earnings & fixed charges	$ 47,810	$78,711	$ 63,091
Ratio of earnings to fixed charges	0.53	0.98	0.72
Deficiency	$(42,759)	$(1,422)	$(24,072)

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.	Louisiana
Crosstex North Texas Pipeline, L.P.	Louisiana
Crosstex North Texas Gathering, L.P.	Louisiana
Crosstex Processing Services, LLC	Louisiana
Crosstex Pelican, LLC	Louisiana
Crosstex NGL Marketing, L.P.	Louisiana
Crosstex NGL Pipeline, L.P.	Louisiana
Sabine Pass Plant Facility Joint Venture	Louisiana
Crosstex Permian, LLC	Louisiana
Crosstex Permian II, LLC	Louisiana
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
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 and 333-159140 on Forms S-8 and No 333-166663 on Form S-3 of Crosstex Energy, L.P. and subsidiaries of our reports dated March 1, 2013, with respect to the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2012 and 2011, 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, 2012, and the effectiveness of internal control over financial reporting as of December 31, 2012, which reports appear in the December 31, 2012 annual report on Form 10-K of Crosstex Energy, L.P. and subsidiaries.

/s/ KPMG LLP

Dallas, Texas
March 1, 2013

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: March 1, 2013

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: March 1, 2013

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, 2012 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: March 1, 2013

/s/ MICHAEL J. GARBERDING

Michael J. Garberding
Executive Vice President and
Chief Financial Officer

Date: March 1, 2013

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.