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, 2009

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: 000-50536

CROSSTEX ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**52-2235832**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
2501 CEDAR SPRINGS DALLAS, TEXAS	**75201**
(Address of principal executive offices)	*(Zip Code)*

(214) 953-9500

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, Par Value $0.01 Per Share	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 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 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 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 voting and non-voting common equity held by non-affiliates of the registrant was approximately $96,476,248 on June 30, 2009, based on $4.17 per share, the closing price of the Common Stock as reported on the NASDAQ Global Select Market on such date.

At February 16, 2010, there were 46,541,360 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Registrant's Proxy Statement relating to its 2010 Annual Stockholders' Meeting to be filed with the Securities and Exchange Commission are incorporated by reference herein into Part III of this Report.

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DESCRIPTION

CROSSTEX ENERGY, INC.

PART I

Item 1. *Business*

General

Crosstex Energy, Inc. is a Delaware corporation, formed in April 2000. We completed our initial public offering in January 2004. Our shares of common stock are listed on the NASDAQ Global Select Market under the symbol “XTXI”. 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. In the “Investors” section of our web site, we post the following filings 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 term “Crosstex Energy, Inc.” as well as the terms “our,” “we,” and “us,” or like terms, are sometimes used as references to Crosstex Energy, Inc. and its consolidated subsidiaries. References in this report to “Crosstex Energy, L.P.,” the “Partnership,” “CELP” or like terms refer to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. together with its consolidated subsidiaries.

CROSSTEX ENERGY, INC.

Our assets consist almost exclusively of partnership interests in Crosstex Energy, L.P., a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs. These partnership interests consist of the following:

- 16,414,830 common units representing an aggregate 25.0% limited partner interest in the Partnership as of January 31, 2010, and

- 100.0% ownership interest in Crosstex Energy GP, L.P., the general partner of the Partnership, which owns a 2.0% general partner interest and all of the incentive distribution rights in the Partnership.

Our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. The Partnership is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership’s business or to provide for future distributions.

The incentive distribution rights entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

Prior to 2009, we received quarterly distributions from the Partnership with the last distribution for the fourth quarter of 2008 received in February 2009. During 2009, the Partnership’s ability to distribute available cash was contractually restricted by the terms of its credit facility due to its high leverage ratios and it ceased making distributions. Although the Partnership’s new credit facility should not limit its ability to make distributions during 2010 and in the future, any decision to resume cash distributions on its units and the amount of any such distributions would consider maintaining sufficient cash flow in excess of the distribution to continue to move the Partnership towards lower leverage ratios. The Partnership has established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA (earnings before interest, income taxes, depreciation and amortization, non-cash mark-to-market items and other miscellaneous non-cash items) of less than 4.0 to 1.0, and the Partnership does not currently expect to resume cash distributions on its outstanding units until it achieves such a ratio of less than 4.5 to 1.0 (pro forma for any distribution). The Partnership will also consider general economic conditions and its outlook for business as it determines to pay any distribution.

Since our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own, we do not expect to receive any significant cash flows until the Partnership is able to improve its leverage ratio and begin making distributions again. As of December 31, 2009, we have cash of $9.9 million which we expect to be sufficient to pay our expenses and federal income taxes and to fund our general partner contributions over the next several years based on our forecasted cash flows. We do not anticipate making any future dividend payments until we begin receiving distributions from the Partnership again.

Historically we have paid dividends to our stockholders on a quarterly basis equal to the cash we receive from our Partnership distributions, less reserves for expenses, future dividends and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner's 2.0% general partner interest; and
- cash reserves our board of directors believed were prudent to maintain.

Our ability to pay dividends is limited by the Delaware General Corporation Law, which provides that a corporation may only pay dividends out of existing "surplus," which is defined as the amount by which a corporation's net assets exceeds its stated capital. While our ownership of the general partner and the common units of the Partnership are included in our calculation of net assets, the value of these assets may decline to a level where we have no "surplus," thus prohibiting us from paying dividends under Delaware law.

So long as we own the Partnership's general partner, under the terms of an omnibus agreement with the Partnership we are prohibited from engaging in the business of gathering, transmitting, treating, processing, storing and marketing natural gas and transporting, fractionating, storing and marketing NGLs, except to the extent that the Partnership, with the concurrence of a majority of its independent directors comprising its conflicts committee, elects not to engage in a particular acquisition or expansion opportunity. The Partnership may elect to forego an opportunity for several reasons, including:

- the nature of some or all of the target's assets or income might affect the Partnership's ability to be taxed as a partnership for federal income tax purposes;
- the board of directors of Crosstex Energy GP, LLC, the general partner of the general partner of the Partnership, may conclude that some or all of the target assets are not a good strategic opportunity for the Partnership; or
- the seller may desire equity, rather than cash, as consideration or may not want to accept the Partnership's units as consideration.

We have no present intention of engaging in additional operations or pursuing the types of opportunities that we are permitted to pursue under the omnibus agreement, although we may decide to pursue them in the future, either alone or in combination with the Partnership. In the event that we pursue the types of opportunities that we are permitted to pursue under the omnibus agreement, our board of directors, in its sole discretion, may retain all, or a portion of, the cash distributions we receive on our partnership interests in the Partnership to finance all, or a portion of, such transactions, which may reduce or eliminate dividends paid to our stockholders.

CROSSTEX ENERGY, L.P.

Crosstex Energy, L.P. is an independent midstream energy company engaged in the gathering, transmission, processing and marketing of natural gas and NGLs. It connects the wells of natural gas producers in its market areas to its gathering systems, processes natural gas for the removal of NGLs, fractionates NGLs into purity products and markets those products for a fee, transports natural gas and ultimately provides natural gas to a variety of markets. It purchases natural gas from natural gas producers and other supply points and sells that natural gas to utilities, industrial consumers, other marketers and pipelines. It operates processing plants that process gas transported to the plants by major interstate pipelines or from its own gathering systems under a variety of fee arrangements. In addition, it purchases natural gas from producers not connected to its gathering systems for resale and sells natural gas on behalf of producers for a fee.

As generally used in the energy industry and in this document, the following terms have the following meanings:

/d = per day
Bbls = barrels
Bcf = billion cubic feet
Btu = British thermal units
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid

Capacity volumes for the Partnership's 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 throughput of 100,000 MMBtu.

Operations of the Partnership

The Partnership focuses on the gathering, processing, transmission and marketing of natural gas and NGLs. Its combined midstream assets consist of over 3,300 miles of natural gas gathering and transmission pipelines, nine natural gas processing plants and three fractionators located in two primary regions: north Texas and Louisiana. Its gathering systems consist of a network of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. The Partnership's transmission pipelines primarily receive natural gas from its gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. Its processing plants remove NGLs from a natural gas stream and its fractionators separate the NGLs into separate NGL products, including ethane, propane, iso- and normal butanes and natural gasoline.

The Partnership assets include the following:

- *North Texas Assets.* The North Texas Assets are comprised of gathering, processing and transmission assets serving producers active in the Barnett Shale. The gathering systems in north Texas consist of approximately 600 miles of gathering lines with total capacity of approximately 1,100 MMcf/d and total throughput of approximately 793,000 MMBtu/d for the year ended December 31, 2009. Processing facilities in north Texas include three gas processing plants with a total processing capacity of 280 MMcf/d. Total processing throughput averaged 219,000 MMBtu/d for the year ended December 31, 2009. Transmission assets consist of a 140-mile pipeline from an area near Fort Worth, Texas to a point near Paris, Texas, and related facilities. The capacity on the North Texas Pipeline, or NTP, is approximately 375 MMcf/d. The NTP connects production from the Barnett Shale to markets in north Texas and to markets accessed by the Natural Gas Pipeline Company, or NGPL, Kinder Morgan, Houston Pipeline, or HPL, Atmos, Gulf Crossing and other markets. For the year ended December 31, 2009, the total throughput on the NTP was approximately 318,000 MMBtu/d.

- *Crosstex LIG System.* The Crosstex LIG system is one of the largest intrastate pipeline systems in Louisiana, consisting of approximately 2,100 miles of gathering and transmission pipeline, with an average total throughput of approximately 900,000 MMBtu/d for the year ended December 31, 2009. The system also includes two operating, on-system processing plants, Plaquemine and Gibson, with an average throughput of approximately 269,000 MMBtu/d for the year ended December 31, 2009. The system has access to both rich and lean gas supplies. These supplies reach from the Haynesville Shale in north Louisiana to new onshore production in south central and southeast Louisiana. Crosstex LIG has a variety of transportation and industrial sales customers, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans.

- *South Louisiana Processing and NGL Assets.* The Partnership's south Louisiana natural gas processing and liquids assets include a total of 2.0 Bcf/d of processing capacity, 66,000 Bbls/d of fractionation capacity, 2.4 million barrels of underground storage and approximately 400 miles of liquids transport lines. The assets include the Eunice processing plant and fractionation facility; the Pelican, Sabine and Blue Water processing plants; the Riverside fractionation plant; the Napoleonville storage facility; the Cajun Sibon pipeline system and the Intracoastal Pipeline. Total processing throughput averaged 856,000 MMBtu/d during December 2009. The Eunice plant is connected to onshore gas supply, as well as continental shelf and deepwater gas production. The Pelican and Sabine plants are connected with continental shelf and deepwater gas. The various plants have downstream connections to the ANR Pipeline, Florida Gas Transmission, Texas Gas Transmission, Tennessee Gas Pipeline and Transco.

Business Strategy

From the inception of the Partnership in 2002 until the second half of 2008, the Partnership's long-term strategy had been to increase distributable cash flow per unit by accomplishing economies of scale through new construction or expansion in core operating areas and making accretive acquisitions of assets that are essential to the production, transportation and marketing of natural gas and NGLs. In response to volatility in the commodity and capital markets over the last 18 months and other events, including the substantial decline in commodity prices, the Partnership adjusted its business strategy in the fourth quarter 2008 and in 2009 to focus on maximizing liquidity, improving the balance sheet through debt reduction and other methods, maintaining a stable asset base, improving the profitability of its assets by increasing their utilization while controlling costs and reducing capital expenditures. Consistent with this strategy, the Partnership divested non-core assets since October 2008 for aggregate sale proceeds of $618.7 million and substantially reduced its outstanding debt. During 2010 the Partnership plans to continue its focus on (i) improving existing system profitability, (ii) continuing to improve the balance sheet and financial flexibility and (iii) pursuing strategic acquisitions and undertaking selective construction and expansion opportunities. Key elements of the strategy will include the following:

- *Improve existing system profitability.* The Partnership intends to operate its existing asset base to enhance profitability by continuing initiatives to maximize utilization by improving operations, reducing operating costs and renegotiating contracts, when appropriate, to improve economics. The Partnership has a solid base of assets that are well located to benefit from the continued growth in the Barnett Shale in north Texas and the new growth anticipated from the Haynesville Shale located in northern Louisiana. It markets services directly to both producers and end users in order to connect new supplies of natural gas, contract new end user deliveries, improve margins and manage operations to fully utilize its systems' capacities. As part of this process, the Partnership focuses on providing a full range of services to producers and end users, including supply aggregation and transportation and hedging, which it believes provides a competitive advantage when competing for sources of natural gas supply.

- *Continue to improve the balance sheet and financial flexibility.* The Partnership intends to continue to improve its balance sheet and financial flexibility. It has established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA (earnings before interest, income taxes, depreciation and amortization, non-cash mark-to-market items and other miscellaneous non-cash items) of less than 4.0 to 1.0, and it does not currently expect to resume cash distributions on its outstanding units until it achieves such a ratio of less than 4.5 to 1.0 (pro forma for any distribution). In addition, any decision to resume cash distributions on partnership units and the amount of any such distributions would consider maintaining sufficient cash flow in excess of the distribution to continue to move towards lower leverage levels. The

Partnership will also consider general economic conditions and the outlook for its business as it determines to pay any distribution. The Partnership's 2010 capital expenditure budget includes approximately $25.0 million of identified growth projects, and it expects to fund such expenditures with internally generated cash flow, with any excess cash flow applied towards debt, working capital or new projects. The Partnership will also consider the use of alternative financing strategies such as entering into joint venture arrangements. As of February 12, 2010, after repayment of existing debt and borrowings under new debt agreements in January and early February 2010 discussed under "Recent Developments," the Partnership has approximately $193.1 million of available capacity for additional borrowings and potential letters of credit under its new credit facility. The Partnership believes that availability under its new credit facility, its ability to issue additional partnership units and enter into strategic joint venture arrangements should provide it with the financial flexibility to facilitate the execution of its business strategy.

- *Pursue strategic acquisitions and undertake selective construction and expansion opportunities ("organic growth").*

  - The Partnership intends to use its acquisition and integration experience to continue to make strategic acquisitions of assets that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of the acquired asset. It pursues acquisitions that it believes will add to existing core areas in order to capitalize on existing infrastructure, personnel and producer and consumer relationships. The Partnership also examines opportunities to establish positions in new areas in regions with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas, primarily through the acquisition or development of key assets that will serve as a platform for further growth.

  - The Partnership also intends to leverage its existing infrastructure and producer and customer relationships by expanding existing systems to meet new or increased demand for gathering, transmission, processing and marketing services. Substantially all of its capital projects during 2009 and its planned projects for 2010 target these types of opportunities.

  - The Partnership will consider the construction of facilities and systems in new areas in regions with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas that lack midstream infrastructure to process and/or transport the natural gas. It believes its existing infrastructure and construction experience provide a competitive advantage for such expansion opportunities. For example:

    - The Partnership established a new core area through the acquisition of LIG Pipeline Company and subsidiaries, which is collectively referred to as Crosstex LIG, in 2004, thereby acquiring one of the largest intrastate pipeline systems in Louisiana. As a result of this acquisition, in 2006 and 2007 the Partnership had the opportunity to expand the system in north Louisiana in response to increasing production from the Cotton Valley formation, from a capacity of approximately 40 MMcf/d to approximately 275 MMcf/d. It further expanded the system in north Louisiana during 2008 and 2009, increasing its capacity to 410 MMcf/d as of December 31, 2009 to take advantage of the increasing production and producer needs in the Haynesville Shale.

    - In 2006, the Partnership established a new core area in north Texas by adding the natural gas gathering pipeline systems and related facilities acquired from Chief Holdings LLC, or Chief, to its NTP, and other operations in the Barnett Shale area. Immediately prior to the acquisition, the Partnership had completed construction on its NTP. Since the 2006 acquisition, the Partnership has expanded its gathering system in north Texas and connected in excess of 500 new wells and significantly increased acreage dedicated to its systems. The Partnership has also constructed three gas processing plants with total processing capacity in the Barnett Shale of 280 MMcf/d.

- In 2005, the Partnership acquired the south Louisiana processing business from El Paso Corporation, which included a lease of the Eunice NGL processing plant and fractionation facility. In October 2009, it acquired the Eunice NGL processing plant and fractionation facility, which will eliminate $12.2 million per year in lease expense and provide opportunities for optimization of the facility. In December 2009, the Partnership acquired the Intracoastal Pipeline, which it was using under a lease arrangement and which is integrated with its NGL system in south Louisiana. Not only will the acquisition of the Intracoastal Pipeline eliminate lease expense, but at the time of the acquisition the partnership also received additional dedications of liquids volumes into its systems from another operator in the area.

Recent Developments

In the fourth quarter of 2008, the Partnership adjusted its business strategy to focus on maximizing liquidity, reducing debt, maintaining a stable asset base, improving the profitability of assets by increasing their utilization while controlling costs and reducing capital expenditures. The Partnership is successfully executing its plan as highlighted by the following accomplishments:

- *Sold Non-Core Assets.* The Partnership sold $618.7 million of non-core assets and repaid approximately $500.0 million in long-term indebtedness from the sales proceeds over the last 15 months. In November 2008, the Partnership sold its 12.4% interest in the Seminole gas processing plant for $85.0 million. In the first quarter of 2009, the Partnership sold its Arkoma system for approximately $10.7 million. In August 2009, the Partnership sold its midstream assets in Alabama, Mississippi and south Texas for approximately $217.6 million. In addition, in October 2009, the Partnership sold its natural gas treating business for $265.4 million. The Partnership also sold its east Texas midstream assets on January 15, 2010 for $40.0 million.

- *Reduced Capital Expenditures.* The Partnership reduced its capital expenditures from over $275.6 million in 2008 to $101.4 million in 2009 and focused its capital projects on lower risk projects with higher expected returns.

- *Reduced Operating and General and Administrative Expenses*. The Partnership reduced its operating expenses from continuing operations to $110.4 million for the year ended December 31, 2009 from $125.8 million for the year ended December 31, 2008 and general and administrative expenses from continuing operations to $59.9 million for the year ended December 31, 2009 from $68.9 million for the year ended December 31, 2008 by reducing staffing and controlling costs. General and administrative expenses for the year ended December 31, 2009 also include non-recurring costs totaling $4.4 million associated with severance payments, lease termination costs and bad debt expense due to the SemStream, L.P. bankruptcy.

- *Acquired Certain Assets in Our Core Areas.* The Partnership acquired the Eunice NGL processing plant and fractionation facility in October 2009 for $23.5 million in cash and the assumption of $18.1 million in debt. It originally acquired the contract rights associated with the Eunice plant as part of the south Louisiana acquisition in November 2005 and operated and managed the plant under an operating lease with an unaffiliated third party prior to the recent acquisition. This acquisition will eliminate lease obligations of $12.2 million per year. The Partnership also acquired the Intracoastal Pipeline located in southern Louisiana for approximately $10.3 million in December 2009. Both of these acquisitions were designed to enhance its NGL business.

- *Sale of Preferred Units.* On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions. The 14,705,882 preferred units are convertible 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 after three years, subject to certain conditions. The preferred units are not redeemable but will pay 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. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if the Partnership pays a cash distribution on common units.

- *Issuance of Senior Unsecured Notes*. On February 10, 2010, the Partnership issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes due 2018 (the "notes" or "senior unsecured notes") at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under its new credit facility discussed below, were used to repay in full amounts outstanding under the existing 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 existing credit facility. The notes are unsecured and unconditionally guaranteed on a senior basis by certain of the Partnership's direct and indirect subsidiaries, including substantially all of its current subsidiaries. Interest payments will be paid semi-annually in arrears starting in August 2010. The Partnership has the option to redeem all or a portion of the notes at any time on or after February 15, 2014, at the specified redemption prices. Prior to February 15, 2014, it may redeem the notes, in whole or in part, at a "make-whole" redemption price. In addition, it may redeem up to 35% of the notes prior to February 15, 2013 with the cash proceeds from certain equity offerings.

- *New Credit Facility.* In February 2010, the Partnership amended and restated its existing secured bank credit facility with a new syndicated secured bank credit facility (the "new credit facility"), which will be guaranteed by substantially all of its subsidiaries. The new credit facility has a borrowing capacity of $420.0 million, and matures in February 2014. Obligations under the new credit facility will be secured by first priority liens on substantially all of the Partnership 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 its equity interests in substantially all of its subsidiaries. Under the new credit facility, borrowings will bear interest at the Partnership's option at the British Bankers Association LIBOR Rate plus an applicable margin, or 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, in each case plus an applicable margin. The Partnership will pay a per annum fee on all letters of credit issued under the new credit facility, and it will pay a commitment fee of 0.50% per annum on the unused availability under the new credit facility. The letter of credit fee and the applicable margins for its interest rate vary quarterly based on its leverage ratio.

Partnership Assets

North Texas Assets. The Partnership's NTP which commenced service in April 2006, consists of a 140-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas. The initial capacity of the NTP was approximately 250 MMcf/d. In 2007, the capacity on the NTP was expanded to a total of approximately 375 MMcf/d. The NTP connects production from the Barnett Shale to markets in north Texas and to markets accessed by the Natural Gas Pipeline Company, or NGPL, Kinder Morgan, Houston Pipeline, or HPL, Atmos, Gulf Crossing and other markets. For the year ended December 31, 2009, the total throughput on the NTP was approximately 318,000 MMBtu/d. The new interconnect with Gulf Crossing Pipeline, which commenced service in August 2009, provides customers access to mid-west and east coast markets.

On June 29, 2006, the Partnership acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems included gathering pipelines, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that transaction, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with the acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, the Partnership began expanding its north Texas gathering system.

- *Gathering System.* Since the date of the acquisition through December 31, 2009, the Partnership expanded its gathering system and connected in excess of 500 new wells to the north Texas gathering system and significantly increased the productive acreage dedicated to the system. As of December 31, 2009, total capacity on the north Texas gathering system was approximately 1,100 MMcf/d and total throughput averaged approximately 793,000 MMBtu/d for the year ended December 31, 2009.

- *Processing Facilities.* Since 2006, the Partnership has constructed three gas processing plants with a total processing capacity in the Barnett Shale of 280 MMcf/d, including the Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, the Azle plant, which is a 50 MMcf/d cryogenic processing plant and the Goforth plant, which is a 30 MMcf/d processing plant. Total processing throughput averaged 219,000 MMBtu/d for the year ended December 31, 2009.

The Partnership has budgeted approximately $15.0 million for continued development of its north Texas assets during 2010.

These capital projects represent system expansions that are planned to handle volume growth as well as projects required pursuant to existing obligations with producers to connect new wells to its gathering systems in north Texas.

Louisiana Assets. The Partnership's Louisiana assets include its Crosstex LIG intrastate pipeline system and its gas processing and liquids business in south Louisiana, referred to as the south Louisiana processing assets.

- *Crosstex LIG System.* The Crosstex LIG system is one of the largest intrastate pipeline systems in Louisiana, consisting of approximately 2,100 miles of gathering and transmission pipeline, with an average throughput of approximately 900,000 MMBtu/d for the year ended December 31, 2009. The system also includes two operating, on-system processing plants, the Plaquemine and Gibson plants, with an average throughput of 269,000 MMBtu/d for the year ended December 31, 2009. The system has access to both rich and lean gas supplies. These supplies reach from north Louisiana to new onshore production in south central and southeast Louisiana. Crosstex LIG has a variety of transportation and industrial sales customers, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans.

In 2007, the Partnership extended the Crosstex LIG system to the north to reach additional productive areas in the developing natural gas fields south of Shreveport, Louisiana, primarily in the Cotton Valley formation. This extension, referred to as the north Louisiana expansion, consists of 63 miles of 24" mainline with 9 miles of gathering lateral pipeline. The north Louisiana expansion bisects the developing Haynesville Shale gas play in north Louisiana. The north Louisiana expansion was operating at near capacity during 2008 as the Haynesville gas was beginning to develop so the Partnership added 35 MMcf/d of capacity by adding compression during the third quarter of 2008 bringing the total capacity of the north Louisiana expansion to approximately 275 MMcf/d. The Partnership continued the expansion of its north Louisiana system during 2009 increasing capacity by 100 MMcf/d in July 2009 by adding compression. It increased capacity by another 35 MMcf/d with a new interconnect into an interstate pipeline in December 2009 and bringing total capacity to 410 MMcf/d by the end of 2009. The Partnership has long-term firm transportation agreements subscribing to all of the incremental capacity added during 2009. In addition, it added compression during 2009 between the southern portion of the Crosstex LIG system and the northern expansion of the Crosstex LIG system, which increased the capacity for moving gas from the north LIG system to markets in the south to 145 MMcf/d. Interconnects on the north Louisiana expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission, Trunkline Gas and Tennessee Gas Pipeline.

The Partnership has budgeted approximately $10.0 million to add an additional 30 MMcf/d of fully contracted capacity in north Louisiana during 2010.

- *South Louisiana Processing and NGL Assets.* Natural gas processing capacity available to the Gulf Coast producers continues to exceed demand. During 2007, 2008, and 2009 the Partnership completed a number of operational changes at its Eunice facility and other plants to idle certain equipment, reduce operating expenses and reconfigure operations to manage the lower utilization. In addition, the Partnership increased focus on upstream markets and opportunities through integration of the Crosstex LIG system and south Louisiana processing assets to improve overall performance. In 2008, its south Louisiana assets were negatively impacted by hurricanes Gustav and Ike, which came ashore in September 2008. Although the Partnership assets did not sustain substantial physical damage, several offshore platforms and pipelines owned by third parties transporting gas production to Pelican, Eunice, Sabine Pass and Blue Water processing plants were damaged by the storms. Substantially all of the production from the pipeline systems supplying Partnership plants was restored to pre-hurricane levels by September 2009. The south Louisiana processing assets include the following:

    - *Eunice Processing Plant and Fractionation Facility.* The Eunice processing plant is located in south central Louisiana, has a capacity of 750 MMcf/d and processed approximately 380,000 MMBtu/d during December 2009. 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, or TGT. The Eunice fractionation facility, which was idled in August 2007, has a capacity of 36,000 barrels per day of liquid products. Beginning in August 2007, the liquids from the

Eunice processing plant were transported through the Cajun Sibon pipeline system to the Riverside plant for fractionation. The Eunice fractionation facility, when operational, produces ethane, propane, iso-butane, normal butane and natural gasoline for various customers. The fractionation facility is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility. The Partnership owned the contract rights associated with the Eunice plant and operated and managed the plant under an operating lease with an unaffiliated third party through October 2009. In October 2009, it acquired the Eunice plant for $23.5 million in cash and the assumption of $18.1 million in debt by buying out the operating lease, thereby eliminating $12.2 million of annual lease obligations.

- *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. During December 2009, the plant processed approximately 340,000 MMBtu/d. The Pelican plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline.

- *Sabine Pass Processing Plant.* The Sabine Pass processing plant is located east of the Sabine River at Johnson's Bayou, Louisiana and has a processing capacity of 300 MMcf/d of natural gas. The Sabine Pass plant is connected to continental shelf and deepwater gas production with downstream connections to Florida Gas Transmission, Tennessee Gas Pipeline (TGP) and Transco. The plant processed approximately 107,000 MMBtu/d during December 2009.

- *Blue Water Gas Processing Plant.* The Partnership acquired a 23.85% interest in the Blue Water gas processing plant in the November 2005 El Paso acquisition and acquired an additional 35.42% interest in May 2006, at which time it became the operator of the plant. The plant has a net capacity to the Partnership's interest of 186 MMcf/d. During 2008, TGP acquired Columbia Gulf Transmission's ownership share in the Blue Water pipeline. In January 2009, TGP reversed the flow of the gas on the pipeline thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system and the plant did not operate during the nine months ended September 30, 2009. In November 2009, the plant was restarted to process the reverse flow stream on TGP. The gas composition of the reverse TGP stream is leaner in NGL content, but may be profitable to process during periods of high fractionation spreads. The plant is expected to operate in this mode periodically as fractionation spread and volumes dictate. When the reverse stream is processed, the Partnership earns all of the margin from processing the gas under a straddle agreement with TGP.

- *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 30,000 Bbls/d of liquids products and fractionates liquids delivered by the Cajun Sibon pipeline system from the Eunice, Pelican and Blue Water plants or by truck. The Riverside facility has above-ground storage capacity of approximately 102,000 barrels.

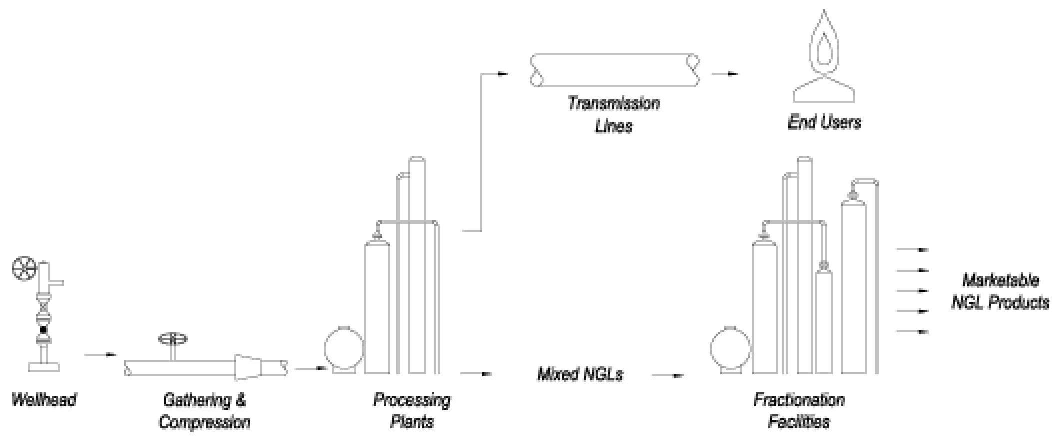
- *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of approximately 2.4 million barrels of underground storage from two existing caverns. The caverns are currently operated in propane and butane service and space is sold to customers for a fee.

- *Cajun Sibon Pipeline System.* The Cajun Sibon pipeline system consists of approximately 400 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 plants to either the Riverside fractionator or to third party fractionators when necessary. Alternate deliveries can be made to the Eunice fractionation facility when operational.

- *Intracoastal Pipeline.* In December 2009, the Partnership acquired the Intracoastal Pipeline from a subsidiary of Chevron Midstream Pipelines LLC. The pipeline consists of approximately 62 miles of six and eight inch pipeline and extends from Patterson to Henry in southern Louisiana. The pipeline connects the Pelican processing plant to the Cajun Sibon pipeline system and accesses other third party processing plants in the region. Prior to the Partnership's acquisition, it utilized portions of the Intracoastal Pipeline under a long-term lease arrangement. This acquisition eliminates approximately $1.3 million of annual lease expense. The Partnership has also entered into an agreement to use the system to bring additional liquids into its NGL system.

Industry Overview

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



The midstream natural gas industry is the link between exploration and production of natural gas 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 producing wells.

Natural gas gathering. The natural gas gathering process follows the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression 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 throughput from all connected wells. Because wells produce 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. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it will be unable to overcome the higher gathering system pressure. In contrast, if field compression is installed, a declining well can continue delivering natural gas.

Natural gas processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of NGLs and contaminants, such as water, 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 is composed almost entirely of methane and ethane, with moisture and other contaminants removed to very low concentrations. Natural gas is processed not only to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas, but also to separate from the gas those hydrocarbon liquids that have higher value as NGLs. The removal and separation of individual hydrocarbons by processing is possible because of 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, as well as the removal of contaminants.

NGL fractionation. Fractionation is the process by which NGLs are further separated into individual, more valuable components. 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 both 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.

Balancing of Supply and Demand

As the Partnership purchases natural gas, it establishes a margin normally by selling natural gas for physical delivery to third-party users. It can also use over-the-counter derivative instruments or enter into a future delivery obligation under futures contracts on the NYMEX. Through these transactions, the Partnership seeks to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Its policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

Competition

The business of providing gathering, transmission, processing and marketing services for natural gas and NGLs is highly competitive. The Partnership faces strong competition in obtaining natural gas supplies and in the marketing and transportation of natural gas and NGLs. Its competitors include major integrated oil companies, natural gas producers, interstate and intrastate pipelines and other natural gas gatherers and processors. Competition for natural gas 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 the Partnership's competitors offer more services or have greater financial resources and access to larger natural gas supplies than it does. The competition differs in different geographic areas.

In marketing natural gas and NGLs, the Partnership has 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 the Partnership's marketing operations.

The Partnership faces 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 its competitors have greater financial resources or lower capital costs, or are willing to accept lower returns or greater risks. The Partnership's competition differs by region and by the nature of the business or the project involved.

Natural Gas Supply

The Partnership's transmission pipelines have connections with major interstate and intrastate pipelines, which it believes have ample supplies of natural gas in excess of the volumes required for these systems. In connection with the construction and acquisition of its gathering systems, the Partnership evaluates well and reservoir data publicly available or furnished by producers or other service providers 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, the Partnership believes that there should be adequate natural gas supply to recoup its investment with an adequate rate of return. The Partnership does not routinely obtain independent evaluations of reserves dedicated to its systems due to the cost and relatively limited benefit of such evaluations. Accordingly, it does not have estimates of total reserves dedicated to its systems or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

The Partnership is diligent in attempting to ensure that it issues credit to only credit-worthy customers. However, the purchase and resale of gas exposes it 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 overall profitability.

During the year ended December 31, 2009, the Partnership had one customer that accounted for approximately 12.2% of consolidated revenues from continuing operations. While this customer represents a significant percentage of consolidated revenues, the loss of this customer would not have a material impact on results of operations.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. The Partnership does not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or FERC, does not directly regulate its operations under the National Gas Act, or NGA. However, FERC's regulation of interstate natural gas pipelines influences certain aspects of the Partnership's business and the market for its 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 the Partnership does not own any interstate pipelines, it does transport gas in interstate commerce. The rates, terms and conditions of service under which the Partnership transports natural gas in its pipeline systems in interstate commerce is subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. In addition, FERC has adopted, or is in the process of adopting, various regulations concerning natural gas market transparency that will apply to some of the pipeline operations. 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.

Intrastate Pipeline Regulation. The Partnership's 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. The Partnership owns a number of natural gas pipelines that it believes 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.

The Partnership is 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 the Partnership sells natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Its sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The Partnership cannot predict the ultimate impact of these regulatory changes on its natural gas marketing operations but does not believe that it will be affected by any such FERC action materially differently than other natural gas marketers with whom it competes.

Environmental Matters

General. The Partnership's operation of processing and fractionation plants, pipelines and associated facilities in connection with the gathering and processing of natural gas and the transportation, fractionation and storage of NGLs is 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. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases its overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines and other facilities. Included in the Partnership's construction and operation costs are capital cost items necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to 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 injunctions or construction bans or delays. We believe that the Partnership currently holds all material governmental approvals required to operate its major facilities. As part of the regular overall evaluation of its operations, the Partnership has implemented procedures to review and update governmental approvals as necessary. We believe that the Partnership's operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on its operating results or financial condition.

The clear 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 the Partnership's possible future operations, and we cannot assure you that the Partnership 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, the Partnership may be unable to pass on those cost increases to its customers. A discharge of hazardous substances or wastes into the environment could, to the extent losses related to the event are not insured, subject the Partnership 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 property. The Partnership 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.

Hazardous Substance and Waste. To a large extent, the environmental laws and regulations affecting the Partnership's operations relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water, and include measures to prevent and control pollution. 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 "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 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" as well as natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of future, ordinary operations, the Partnership may generate wastes that may fall within the definition of a "hazardous substance." However, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, the Partnership 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. The Partnership has not received any notification that it may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state laws.

The Partnership also generates, 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 comparable state statutes. The Partnership is not currently required to comply with a substantial portion of the RCRA requirements because its operations generate minimal quantities of hazardous wastes. From time to time, the Environmental Protection Agency, or EPA, has 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 it that are currently classified 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 regulations may result in an increase in the Partnership's capital expenditures or plant operating expenses.

The Partnership currently owns or leases, and has in the past owned or leased, and in the future may own or lease, properties that have been used over the years for 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 the Partnership during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom the Partnership had no control as to such entities' handling of hydrocarbons or other wastes and the manner in which such substances may have been disposed of or released. These properties and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, the Partnership could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. The Partnership's 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 the Partnership's facilities, and impose various monitoring and reporting requirements. Pursuant to these laws and regulations, the Partnership 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. The Partnership 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 the Partnership's financial condition or operating results, and the requirements are not expected to be more burdensome to the Partnership than any similarly situated company.

Air emissions associated with operations in the Barnett Shale area have come under recent scrutiny. In 2009, the Texas Commission on Environmental Quality (TCEQ) conducted comprehensive monitoring of air emissions in the Barnett Shale area, in response to public concerns about high concentrations of benzene in the air near drilling sites and natural gas processing facilities. A comprehensive report detailing the monitoring results and their potential health impacts is expected to be finalized in early 2010. Environmental groups have advocated increased regulation in the Barnett Shale area and these groups as well as at least one state representative have further advocated a moratorium on permits for new gas wells until TCEQ completes its analysis. Also, the EPA recently entered into a settlement that requires it to reevaluate regulations for the control of air emissions from natural gas production facilities. Changes in laws or regulations imposing emission limitations, pollution control technology requirements or other regulatory requirements or any restriction on permitting of natural gas production facilities in the Barnett Shale area could have an adverse effect on the Partnership's 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 U.S. Congress is actively considering legislation to reduce such emissions. In addition, at least one-third 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. In addition, EPA is taking steps that would result in the regulation of greenhouse gases as pollutants under the federal Clean Air Act. Furthermore, in September 2009, EPA finalized regulations that require monitoring and reporting of greenhouse gas emissions on an annual basis, including extensive greenhouse gas monitoring and reporting requirements, beginning in 2010. Although the greenhouse gas reporting rule does not control greenhouse gas emission levels from any facilities, it will still cause the Partnership to incur monitoring and reporting costs for emissions that are subject to the rule. Some of the Partnership's facilities include source categories that are subject to the greenhouse gas reporting requirements included in the final rule. However, EPA postponed a decision on proposed Subpart W to 40 CFR part 98, which would have applied to fugitive and vented methane emissions from the oil and gas sector, including natural gas transmission compression. The prospect remains that EPA will adopt regulations that require reporting of fugitive and vented methane emissions from the oil and gas industry, which will increase the Partnership's monitoring and reporting costs. In December 2009, EPA also issued findings that greenhouse gases in the atmosphere endanger public health and welfare, and that emissions from mobile sources cause or contribute to greenhouse gases in the atmosphere. The endangerment findings will not immediately affect the Partnership's operations, but standards eventually promulgated pursuant to these findings could affect its operations and ability to obtain air permits for new or modified facilities. Legislation and regulations relating to control or reporting of greenhouse gas emissions are also in various stages of discussions or implementation in about one-third of the states. Lawsuits have been filed seeking to force the federal government to regulate greenhouse gases emissions under the Clean Air Act and to require individual companies to reduce greenhouse gas emissions from their operations. These and other lawsuits may result in decisions by state and federal courts and agencies that could impact the Partnership's operations and ability to obtain certifications and permits to construct future projects.

Passage of climate change legislation or other federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which the Partnership conducts business could adversely affect the demand for the products it stores, transports and processes, and depending on the particular program adopted could increase the costs of its operations, including costs to operate and maintain its facilities, install new emission controls on its facilities, acquire allowances to authorize its greenhouse gas emissions, pay any taxes related to its greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. The Partnership may be unable to recover any such lost revenues or increased costs in the rates it charges its customers, and any such recovery may depend on events beyond its control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in the Partnership's revenues or increases in its expenses as a result of climate control initiatives could have adverse effects on its business, financial position, results of operations and prospects.

Clean Water Act. 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 natural gas liquid 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. The Partnership believes that it is 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 its results of operations.

It is customary 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 the Partnership's customers, particularly in Barnett Shale and Haynesville Shale regions of its operations. 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 have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. In particular, the U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for the Partnership's customers to perform hydraulic fracturing. Any increased federal, state or local regulation could reduce the volumes of natural gas that the Partnership's customers move through its gathering systems which would materially adversely affect its revenues and results of operations.

Employee Safety. The Partnership is 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. The Partnership believes that its operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Safety Regulations. The Partnership's pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, as amended, or HLPSA, and the Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192, effective February 14, 2004 relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA covers crude oil, carbon dioxide, NGL and petroleum products pipelines and requires any entity which owns or operates pipeline facilities to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. The Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192 (PIM) requires operators of gas 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 addition, the Railroad Commission of Texas, or TRRC, regulates the Partnership's pipelines in Texas under its own pipeline integrity management rules. The Texas rule includes certain transmission and gathering lines based upon pipeline diameter and operating pressures. The Partnership believes that its pipeline operations are in substantial compliance with applicable HLPSA and PIM 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 HLPSA or PIM requirements will not have a material adverse effect on its results of operations or financial positions.

Office Facilities

We occupy approximately 95,400 square feet of space at our executive offices in Dallas, Texas under a lease expiring in June 2014, approximately 25,100 square feet of office space for the Partnership's south Louisiana operations in Houston, Texas with lease terms expiring in January 2013 and approximately 11,800 square feet of office space for its north Texas operations in Fort Worth, Texas, with lease terms expiring in April 2013.

Employees

As of December 31, 2009, the Partnership (through its subsidiaries) employed approximately 456 full-time employees. Approximately 244 of the employees were general and administrative, engineering, accounting and commercial personnel and the remainders were operational employees. The Partnership is not party to any collective bargaining agreements, and has not had any significant labor disputes in the past. We believe that the Partnership has good relations with its 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 pay dividends to our shareholders and the trading price of our common shares 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.

Our cash flow consists almost exclusively of distributions from Crosstex Energy, L.P.

Our only cash-generating assets are our partnership interests in Crosstex Energy, L.P. Our cash flow is therefore completely dependent upon the ability of the Partnership to make distributions to its partners. Prior to 2009, we received quarterly distributions from the Partnership with the last distribution for the fourth quarter of 2008 received in February 2009. During 2009, the Partnership's ability to distribute available cash was contractually restricted by the terms of its credit facility due to its high leverage ratios and it ceased making distributions. Although the Partnership's new credit facility should not limit its ability to make distributions during 2010 and in the future, any decision to resume cash distributions on its units and the amount of any such distributions would consider maintaining sufficient cash flow in excess of the distribution to continue to move the Partnership towards lower leverage ratios. The Partnership has established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA of less than 4.0 to 1.0, and the Partnership does not currently expect to resume cash distributions on its outstanding units until it achieves such a ratio of less than 4.5 to 1.0 (pro forma for any distribution). The Partnership will also consider general economic conditions and its outlook for business as it determines to pay any distribution.

The Partnership may not have sufficient available cash each quarter to pay distributions to unitholders. The amount of cash that the Partnership can distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas transported in its gathering and transmission pipelines;
- the level of the Partnership's processing operations;
- the fees the Partnership charges and the margins it realizes for its services;
- the price of natural gas;

- the relationship between natural gas and NGL prices; and
- its level of operating costs;

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

- the level of capital expenditures the Partnership makes;
- the cost of acquisitions, if any;
- its debt service requirements;
- fluctuations in its working capital needs;
- its ability to make working capital borrowings under its bank credit facility to pay distributions;
- prevailing economic conditions; and
- the amount of cash reserves established by the general partner in its sole discretion for the proper conduct of its business.

Because of these factors, the Partnership may not be able, or may not have sufficient available cash to pay distributions to unitholders each quarter. Furthermore, you should also be aware that the amount of cash the Partnership has available for distribution depends primarily upon its cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records net income.

We are largely prohibited from engaging in activities that compete with the Partnership.

So long as we own the general partner of the Partnership, we are prohibited by an omnibus agreement with the Partnership from engaging in the business of gathering, transmitting, treating, processing, storing and marketing natural gas and transporting, fractionating, storing and marketing NGLs, except to the extent that the Partnership, with the concurrence of its independent directors comprising its conflicts committee, elects not to engage in a particular acquisition or expansion opportunity. This exception for competitive activities is relatively limited. Although we have no current intention of pursuing the types of opportunities that we are permitted to pursue under the omnibus agreement such as competitive opportunities that the Partnership declines to pursue or permitted activities that are not competition with the Partnership, the provisions of the omnibus agreement may, in the future, limit activities that we would otherwise pursue.

In our corporate charter, we have renounced business opportunities that may be pursued by the Partnership or by certain stockholders.

In our restated charter and in accordance with Delaware law, we have renounced any interest or expectancy we may have in, or being offered an opportunity to participate in, any business opportunities, including any opportunities within those classes of opportunity currently pursued by the Partnership, presented to:

- persons who are officers or directors of the company or who, on October 1, 2003, were, and at the time of presentation are, stockholders of the company (or to persons who are affiliates or associates of such officers, directors or stockholders), if the company is prohibited from participating in such opportunities by the omnibus agreement; or
- any investment fund sponsored or managed by Yorktown Partners LLC, including any fund still to be formed, or to any of our directors who is an affiliate or designate of these entities.

As a result of this renunciation, these officers, directors and stockholders should not be deemed to be breaching any fiduciary duty to us if they or their affiliates or associates pursue opportunities presented as described above.

Although we control the Partnership, the general partner owes fiduciary duties to the Partnership and the unitholders.

Conflicts of interest exist and may arise in the future as a result of the relationship between us and our affiliates, including the general partner, on the one hand, and the Partnership and its limited partners, on the other hand. The directors and officers of Crosstex Energy GP, LLC have fiduciary duties to manage the general partner in a manner beneficial to us, its owner. At the same time, the general partner has a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and its limited partners. The board of directors of Crosstex Energy GP, LLC will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest or that of our stockholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to the Partnership and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and the Partnership, on the other hand, including obligations under the omnibus agreement;
- the determination of the amount of cash to be distributed to the Partnership's partners and the amount of cash to be reserved for the future conduct of the Partnership's business;
- the determination whether to make borrowings under the capital facility to pay distributions to partners; and
- any decision we make in the future to engage in activities in competition with the Partnership as permitted under our omnibus agreement with the Partnership.

If the general partner is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of the Partnership, its value, and therefore the value of our common stock, could decline.

The general partner may make expenditures on behalf of the Partnership for which it will seek reimbursement from the Partnership. In addition, under Delaware partnership law, the general partner, in its capacity as the general partner of the Partnership, 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 the general partner. To the extent the general partner incurs obligations on behalf of the Partnership, it is entitled to be reimbursed or indemnified by the general partner. In the event that the Partnership is unable or unwilling to reimburse or indemnify the general partner, the general partner may be unable to satisfy these liabilities or obligations, which would reduce its value and therefore the value of our common stock.

The Partnership's profitability is dependent upon prices and market demand for natural gas and NGLs, which are beyond its control and have been volatile.

The Partnership's business is subject to significant risks due to fluctuations in commodity prices. It is directly exposed to these risks primarily in the gas processing component of its business. It is also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of natural gas and NGLs connected to or near its assets and on its margins for transportation between certain market centers. A large percentage of its processing fees are realized under percent of liquids (POL) contracts that are directly impacted by the market price of NGLs. It also realizes processing gross margins under processing margin (margin) contracts. These settlements are impacted by the relationship between NGL prices and the underlying natural gas prices, which is also referred to as the fractionation spread.

A significant volume of inlet gas at the Partnership's south Louisiana and north Texas processing plants is settled under POL agreements. The POL fees are denominated in the form of a share of the liquids extracted and it is not responsible for the fuel or shrink associated with processing. Therefore, revenue under a POL agreement is directly impacted by NGL prices, and the decline of these prices in the second half of 2008 and early 2009 contributed to a significant decline in the Partnership's gross margin from processing.

The Partnership has a number of contracts on its Plaquemine and Gibson processing plants that expose it to the fractionation spread. Under these margin contracts its gross margin is based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state ("shrink") and the cost of fuel to extract during processing. During the second half of 2008 and early 2009, the fractionation spread narrowed significantly as the value of NGLs decreased more than the value of the gas and fuel associated with the processed gas. Thus the gross margin realized under these margin contracts was negatively impacted due to the commodity price environment. Such a decline may negatively impact its gross margin in the future if such declines again.

In the past, the prices of natural gas and NGLs have been extremely volatile and the Partnership expects this volatility to continue. For example, prices of oil, natural gas and NGLs in 2009 were below the market price realized throughout most of 2008. Crude oil prices (based on the New York Mercantile Exchange (the "NYMEX") futures daily close prices for the prompt month) improved during 2009 with prices ranging from a low of $33.98 per Bbl in February 2009 to a high of $81.37 per Bbl in October 2009. Weighted average NGL prices (based on the Oil Price Information Service (OPIS) Mt. Belvieu daily average spot liquids prices) have also improved with prices ranging from a low of $0.58 per gallon in March 2009 to a high of $1.21 per gallon in December 2009. Natural gas prices declined during 2009 with prices ranging from a high of $6.10 per MMBtu in January 2009 to a low of $1.85 per MMBtu in September 2009. Natural gas prices improved during the fourth quarter of 2009, with prices reaching a high of $6.00 per MMBtu in December 2009.

The markets and prices for natural gas and NGLs depend upon factors beyond the Partnership's control. These factors include the supply and demand for oil, 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 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 the Partnership's profitability by influencing drilling activity and well operations, and thus the volume of gas it can gather and process. This volatility may cause the Partnership's gross margin and cash flows to vary widely from period to period. Hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the Partnership's throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in "—The Partnership's use of derivative financial instruments does not eliminate its exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduced income." For a discussion of the Partnership's risk management activities, please read "Item 7A. Qualitative and Quantitative Disclosure about Market Risk."

The Partnership's substantial indebtedness could limit its flexibility and adversely affect its financial health.

The Partnership has a substantial amount of indebtedness. As of December 31, 2009, the Partnership had approximately $873.7 million of indebtedness outstanding. As of February 12, 2010, after repayment of existing debt with proceeds from the sale of preferred units together with proceeds from the issuance of its senior unsecured notes and borrowings under its new credit facility, the Partnership had approximately $790.6 million (including $15.2 million of original issue discount on the senior unsecured notes) of indebtedness outstanding, including $725.0 million of senior unsecured notes and $47.5 million of secured indebtedness outstanding under our new credit facility and $18.1 million of series B secured note associated with the Eunice lease acquisition. The Partnership also had approximately $179.4 million of letters of credit outstanding under its old credit facility as of February 12, 2010 that were subsequently replaced by letters of credit under the new credit facility.

The Partnership's substantial indebtedness could limit its flexibility and adversely affect its financial health. For example, it could:

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

In addition, the Partnership's ability to make scheduled payments or to refinance obligations depends on its successful financial and operating performance. The Partnership cannot assure you that its operating performance will generate sufficient cash flow or that its capital resources will be sufficient for payment of its indebtedness obligations in the future. The Partnership's 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 its control.

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

The Partnership may not be able to obtain additional funding for future capital needs or to refinance its debt, either on acceptable terms or at all.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile, which has caused substantial contraction in the credit and capital markets. These conditions, along with significant write-offs in the financial services sector and current weak economic conditions, have made, and will likely continue to make, it difficult to obtain funding for the Partnership's capital needs. As a result, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. Due to these factors, the Partnership cannot be certain that new debt or equity financing will be available to it on acceptable terms or at all. If funding is not available when needed, or is available only on unfavorable terms, the Partnership may be unable to meet its obligations as they come due. Without adequate funding, the Partnership may be unable to execute its 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 its revenues and results of operations. Further, its customers may increase collateral requirements from the Partnership, including letters of credit which reduce available borrowing capacity, or reduce the business they transact with the Partnership to reduce their credit exposure.

Due to current economic conditions, the Partnership's ability to obtain funding under its new credit facility could be impaired.

The Partnership operates in a capital-intensive industry and relies on its new credit facility to assist in financing a significant portion of its capital expenditures. The Partnership's ability to borrow under its new credit facility may be impaired. Specifically, the Partnership may be unable to obtain adequate funding under its new credit facility because:

- one or more of the Partnership's lenders may be unable or otherwise fail to meet its funding obligations;
- the lenders do not have to provide funding if there is a default under the credit agreement or if any of the representations or warranties included in the agreement are false in any material respect; and
- if any lender refuses to fund its commitment for any reason, whether or not valid, the other lenders are not required to provide additional funding to make up for the unfunded portion.

If the Partnership is unable to access funds under its new credit facility, the Partnership will need to meet its capital requirements, including some of its short-term capital requirements, using other sources. Alternative sources of liquidity may not be available on acceptable terms, if at all. If the cash generated from its operations or the funds the Partnership is able to obtain under its new credit facility or other sources of liquidity are not sufficient to meet its capital requirements, then it may need to delay or abandon capital projects or other business opportunities, which could have a material adverse effect on its results of operations and financial condition.

Due to the Partnership's lack of asset diversification, adverse developments in its gathering, transmission, processing and producer services businesses would materially impact its financial condition.

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

Many of the Partnership's customers' drilling activity levels and spending for transportation on its pipeline system or gathering and processing at its facilities have been, and may continue to be, impacted by the current deterioration in the credit markets.

Many of the Partnership's customers finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. During the last half of 2008 and during 2009, there was a significant decline in the credit markets and the availability of credit. Adverse price changes, coupled with the overall downturn in the economy and the constrained capital markets, put downward pressure on drilling budgets for gas producers, which has resulted in lower volumes that the Partnership otherwise would have seen being transported on its pipeline and gathering systems and processing through its processing plants. The Partnership saw a decline in drilling activity by gas producers in its Barnett Shale area of operation in north Texas during the fourth quarter of 2008 and during 2009. A continued decline in drilling activity or low drilling activity could have a material adverse effect on its operations.

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

Risks of nonpayment and nonperformance by the Partnership's customers are a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by its customers could adversely affect the results of operations and reduce the Partnership's ability to make distributions to its unitholders. Many of the Partnership's customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of the Partnership's customers' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in customers' liquidity and ability to make payment or perform on their obligations to the Partnership. Furthermore, some of the customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to the Partnership.

The Partnership's use of derivative financial instruments does not eliminate its exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduced income.

The Partnership's operations expose it to fluctuations in commodity prices, and its new credit facility exposes the Partnership to fluctuations in interest rates. The Partnership uses over-the-counter price and basis swaps with other natural gas merchants and financial institutions and interest rate swaps with financial institutions. Use of these instruments is intended to reduce its exposure to short-term volatility in commodity prices and interest rates. As of December 31, 2009, the Partnership had hedged only portions of its variable-rate debt and expected natural gas supply, NGL production and natural gas requirements, and had direct interest rate and commodity price risk with respect to the unhedged portions. In addition, to the extent the Partnership hedges its commodity price and interest rate risks using swap instruments, it will forego the benefits of favorable changes in commodity prices or interest rates. In February 2010, the Partnership settled all of its interest rate swaps associated with its existing credit facility when the Partnership repaid the debt outstanding under this facility.

Even though monitored by management, the Partnership's hedging activities may fail to protect it and could reduce earnings and cash flow. Its 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;
- the Partnership's 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 the Partnership seeks protection. For example:
  - the duration of a hedge may not match the duration of the risk against which the Partnership seeks protection;
  - variations in the index used to price a commodity hedge may not adequately correlate with variations in the index used to sell the physical commodity (known as basis risk); and
  - the Partnership may not produce or process sufficient volumes to cover swap arrangements it enters into for a given period. If its actual volumes are lower than the volumes it estimated when entering into a swap for the period, the Partnership might be forced to satisfy all or a portion of its derivative obligation without the benefit of cash flow from its sale or purchase of the underlying physical commodity, which could adversely affect liquidity.

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

The Partnership may not be successful in balancing its purchases and sales.

The Partnership is a party to certain long-term gas sales commitments that it satisfies through supplies purchased under long-term gas purchase agreements. When the Partnership enters into those arrangements, its sales obligations generally match its purchase obligations. However, over time the supplies that the Partnership has under contract may decline due to reduced drilling or other causes and it 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 the Partnership's purchases and sales not to be balanced. If the Partnership's purchases and sales are not balanced, it will face increased exposure to commodity price risks and could have increased volatility in operating income.

The Partnership makes certain 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 the Partnership's margins or even result in losses. For example, the Partnership is a party to one contract where it buys gas on several different production-area indices on its NTP and sells the gas into a different market area index. For the fourth quarter of 2009, this imbalance resulted in a loss of approximately $1.8 million due to basis differentials between the various market prices.

The Partnership must continually compete for natural gas supplies, and any decrease in its supplies of natural gas could adversely affect its financial condition and results of operations.

If the Partnership is unable to maintain or increase the throughput on its systems by accessing new natural gas supplies to offset the natural decline in reserves, its business and financial results could be materially, adversely affected. In addition, the Partnership's future growth will depend, in part, upon whether it can contract for additional supplies at a greater rate than the rate of natural decline in its currently connected supplies.

In order to maintain or increase throughput levels in the Partnership's natural gas gathering systems and asset utilization rates at the Partnership's processing plants and to fulfill its current sales commitments, it must continually contract for new natural gas supplies. The Partnership may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting its ability to connect new wells to its gathering facilities include the Partnership's success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity near its gathering systems. Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. For example, as oil and natural gas prices decreased during the last half of 2008 and the first half of 2009, there was a corresponding decrease in drilling activity. 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 the Partnership's systems. The Partnership has no control over producers and depends on them to maintain sufficient levels of drilling activity. A material decrease in natural gas production or in the level of drilling activity in the Partnership's principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on results of operations and financial position.

The Partnership is vulnerable to operational, regulatory and other risks due to its concentration of assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

The Partnership's operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because it has a significant portion of its assets located in south Louisiana and the Gulf of Mexico. In 2008, the Partnership's business was negatively impacted by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September. These storms resulted in an adverse impact to the Partnership's gross margins of approximately $22.9 million in the last half of 2008. Although the Partnership's assets did not sustain substantial physical damage, several offshore production platforms and pipelines owned by third parties that transport gas production to our Pelican, Eunice, Sabine Pass and Blue Water processing plants in south Louisiana were damaged by the storms. Some of the repairs to these offshore facilities were completed during the fourth quarter of 2008, but gas production to the Partnership's south Louisiana plants did not recover to pre-hurricane levels until September 2009.

The Partnership's concentration of activity in Louisiana and the Gulf of Mexico makes it more vulnerable than many of its 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 the Partnership's operations could experience the same condition at the same time, these conditions could have a relatively greater impact on its results of operations than they might have on other midstream companies who have operations in more diversified geographic areas.

In addition, the Partnership's operations in south Louisiana are dependent upon continued conventional and deep shelf drilling in the Gulf of Mexico. The deep shelf in the Gulf of Mexico is an area that has had limited historical drilling activity. This is due, in part, to its geological complexity and depth. Deep shelf development is more expensive and inherently more risky than conventional shelf drilling. A decline in the level of deep shelf drilling in the Gulf of Mexico could have an adverse effect on the Partnership's financial condition and results of operations.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by the Partnership's customers, which could adversely impact its revenues.

The U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells by our customers, particularly in Barnett Shale and Haynesville Shale regions of the Partnership's operations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for our customers to perform hydraulic fracturing. Many producers make extensive use of hydraulic fracturing in the areas that the Partnership serves and any increased federal, state or local regulation could reduce the volumes of natural gas that they move through the Partnership's gathering systems which would materially adversely affect revenues and results of operations.

A substantial portion of the Partnership's assets are connected to natural gas reserves that will decline over time, and the cash flows associated with those assets will decline accordingly.

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

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

One of the ways the Partnership intends to grow its 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 facilities requires the expenditure of significant amounts of capital, which may exceed our expectations. Generally, the Partnership may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, it may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. The Partnership may also rely on estimates of proved reserves in its 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 to achieve the expected investment return, which could adversely affect the Partnership's results of operations and financial condition. In addition, the Partnership faces the risks of construction delay and additional costs due to obtaining rights-of-way and local permits and complying with federal or state laws and city ordinances, particularly as the Partnership expands its operations into more urban, populated areas such as the Barnett Shale.

Acquisitions typically increase the Partnership's debt and subjects it to other substantial risks, which could adversely affect its results of operations.

From time to time, the Partnership may evaluate and seek to acquire assets or businesses that it believes complement existing business and related assets. The Partnership may acquire assets or businesses that it plans 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;
- the diversion of management's attention from other business concerns;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in the Partnership's indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management's assessment of these risks is necessarily 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 the Partnership's operations and cash flows. If Partnership consummates any future acquisition, its 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 the Partnership will consider in determining the application of these funds and other resources.

Additionally, the Partnership's ability to grow its asset base in the near future through acquisitions may be limited due to its lack of access to capital markets.

The Partnership expects to encounter significant competition in any new geographic areas into which it seeks to expand and its ability to enter such markets may be limited.

If the Partnership expands its operations into new geographic areas, it expects to encounter significant competition for natural gas supplies and markets. Competitors in these new markets will include companies larger than the Partnership, which have both lower capital costs and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, the Partnership may not be able to successfully develop acquired assets and markets located in new geographic areas and its results of operations could be adversely affected.

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

The renewal or replacement of existing contracts with the Partnership's customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond its control, including competition from other pipelines, and the price of, and demand for, natural gas in the markets the Partnership serves. The inability of the Partnership's management to renew or replace its current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on its profitability.

In particular, the Partnership's ability to renew or replace its existing contracts with industrial end-users and utilities impacts its profitability. For the year ended December 31, 2009, approximately 48.5% of the Partnership's sales of natural gas that was transported using its 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 are 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 the Partnership in the marketing of natural gas, the Partnership often competes in the end-user and utilities markets primarily on the basis of price.

The Partnership depends on certain key customers, and the loss of any of its key customers could adversely affect its financial results.

The Partnership derives a significant portion of its 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, the Partnership would be adversely affected unless it was 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.

The Partnership's business involves many hazards and operational risks, some of which may not be fully covered by insurance.

The Partnership's operations are subject to the many hazards inherent in the gathering, compressing, processing and storage of natural gas and NGLs, 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 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 the Partnership's related operations. The Partnership is not fully insured against all risks incident to its business. In accordance with typical industry practice, the Partnership does not have any property insurance on any of it underground pipeline systems that would cover damage to the pipelines. It is 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 the Partnership's operations and financial condition.

The threat of terrorist attacks has resulted in increased costs, and future war or risk of war may adversely impact the Partnership's results of operations and its ability to raise capital.

Terrorist attacks or the threat of terrorist attacks cause instability in the global financial markets and other industries, including the energy industry. Infrastructure facilities, including pipelines, production facilities, and transmission and distribution facilities, could be direct targets, or indirect casualties, of an act of terror. The Partnership's insurance policies generally exclude acts of terrorism. Such insurance is not available at what it believes to be acceptable pricing levels.

Federal, state or local regulatory measures could adversely affect the Partnership's business.

The Partnership's 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. The Partnership's 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. The Partnership cannot predict what effect, if any, such changes might have on its 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 the Partnership transports natural gas in its pipeline systems in interstate commerce are subject to FERC regulation under the Section 311 of the Natural Gas Policy Act. Under these regulations, the Partnership is required to justify its rates for interstate transportation service on a cost-of-service basis, every three years. The Partnership's 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 the Partnership's rates for Section 311 transportation service or intrastate transportation service should be lowered, its business could be adversely affected.

Other state and local regulations also affect the Partnership's business. It is subject to some ratable take and common purchaser statutes in the states where it 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 the Partnership's right as an owner of gathering facilities to decide with whom it will 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 the Partnership operates have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which the Partnership operates 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 the Partnership conducts operations administer federal pipeline safety standards under the Pipeline Safety Act of 1968. The "rural gathering exemption" under the Natural Gas Pipeline Safety Act of 1968 presently exempts substantial portions of its gathering facilities from jurisdiction under that statute, including those portions located outside of cities, towns, or any area designated as residential or commercial, such as a subdivision or shopping center. The "rural gathering exemption," however, may be restricted in the future, and it does not apply to the Partnership's 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.

Compliance with pipeline integrity regulations issued by the United States Department of Transportation in December 2003 or those issued by the 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. The Partnership's costs relating to compliance with the required testing under the TRRC regulations, adjusted to exclude costs associated with discontinued operations, were approximately at $1.1 million, $1.4 million, and $0.1 million for the years ended December 31, 2009, 2008, and 2007, respectively. The Partnership expects the costs for compliance with TRRC and DOT regulations to be approximately $3.7 million during 2010. If the Partnership's pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then it may be required to repair or replace sections of such pipelines, the cost of which cannot be estimated at this time.

As the Partnership's operations continue to expand into and around urban, or more populated areas, such as the Barnett Shale, it may incur additional expenses to mitigate noise, odor and light that may be emitted in its operations, and expenses related to the appearance of its 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 the Partnership's facilities and requiring certain other improvements that increase the cost of its facilities. The Partnership is also subject to claims by neighboring landowners for nuisance related to the construction and operation of its facilities, which could subject it to damages for declines in neighboring property values due to its construction and operation of facilities.

The Partnership's business involves hazardous substances and may be adversely affected by environmental regulation.

Many of the operations and activities of the Partnership's gathering systems, processing plants, fractionators 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 facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by the Partnership or locations to which it has 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 the Partnership's facilities or upon or through which the Partnership's 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 the Partnership's business due to its handling of natural gas and other petroleum substances, air emissions related to its operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. The Partnership may incur material environmental costs and liabilities. Furthermore, its insurance may not provide sufficient coverage in the event an environmental claim is made against it.

The Partnership's 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 being considered by the U.S. Congress relating to the control of greenhouse gas emissions or changes in existing environmental laws or regulations might adversely affect 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 the Partnership's profitability. Changes in laws or regulations could also limit production or the operation of the Partnership's assets or adversely affect its ability to comply with applicable legal requirements or the demand for natural gas, which could adversely affect business and the Partnership's profitability.

The Partnership's success depends on key members of its management, the loss or replacement of whom could disrupt business operations.

The Partnership depends on the continued employment and performance of the officers of the general partner of its general partner and key operational personnel. The general partner of its 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, the Partnership's business operations could be materially adversely affected. The Partnership does not maintain any "key man" life insurance for any officers.

Item 1B. *Unresolved Staff Comments*

We do not have any unresolved staff comments.

Item 2. *Properties*

A description of the Partnership's properties is contained in "Item 1. Business."

Title to Properties

Substantially all of the Partnership's 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. The Partnership has 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 the Partnership's pipeline was built was purchased in fee. The Partnership's processing plants are located on land that it leases or owns in fee.

We believe that the Partnership has satisfactory title to all of its 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 the Partnership's assets or from the Partnership's interest in these assets or should materially interfere with their use in the operation of the business.

Item 3. *Legal Proceedings*

Our operations and those of the Partnership are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we or the Partnership 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 the Partnership continues to expand operations into more urban, populated areas, such as the Barnett Shale, it 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 or 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 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.

In December 2008, Denbury Onshore, LLC ("Denbury") initiated formal arbitration proceedings against Crosstex CCNG Processing Ltd. ("Crosstex Processing"), Crosstex Energy Services, L.P. ("Crosstex Energy"), Crosstex North Texas Gathering, L.P. ("Crosstex Gathering") and Crosstex Gulf Coast Marketing, Ltd. ("Crosstex Marketing"), all wholly-owned subsidiaries of the Partnership, asserting a claim for breach of contract under a gas processing agreement. Denbury alleged damages in the amount of $16.2 million, plus interest and attorneys' fees. Crosstex denied any liability and sought to have the action dismissed. A three-person arbitration panel conducted a hearing on the merits in December 2009. At the close of the evidence at the hearing, the panel granted judgment for Crosstex on one of Denbury's claims, and on February 16, 2010, the panel granted judgment for Denbury on its remaining claims in the amount of $3.0 million plus interest, attorneys' fees and costs. The panel will conduct additional proceedings to determine the amount of attorneys' fees and costs, if any, that should be awarded to Denbury. We estimate that the total award will be between $3.0 million and $4.0 million at the conclusion of these additional proceedings and a liability for this award was accrued as of December 31, 2009.

At times, the Partnership's gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain provided under state law. As a result, the Partnership (or its subsidiaries) is a 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 increase 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 several 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, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed the Partnership approximately $6.2 million, including approximately $3.9 million for June 2008 sales and approximately $2.3 million for July 2008 sales. The Partnership believes the July sales of $2.3 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to Crosstex for an administrative claim in the amount of $2.3 million, but it remains subject to an objection by the lenders' agent. The Partnership evaluated these receivables for collectibility and recorded a provision for bad debt of $3.1 million during the year ended December 31, 2008 and $0.8 million during the year ended December 31, 2009.

Item 4. *Reserved*

PART II

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

Our common stock is listed on the NASDAQ Global Select Market under the symbol "XTXI". Our common stock began trading on January 12, 2004. On February 16, 2010, the closing market price for our common stock was $7.75 per share and there were approximately 13,500 record holders and beneficial owners (held in street name) of the shares of our common stock.

The following table shows the high and low closing sales prices per share, as reported by the NASDAQ Global Select Market, for the periods indicated:

	Common Stock Price Range High	Common Stock Price Range Low	Cash Dividends Paid per Share
2009:			
Quarter Ended December 31	$ 6.57	$ 4.13	—
Quarter Ended September 30	5.60	3.13	—
Quarter Ended June 30	5.40	1.79	—
Quarter Ended March 31	6.71	0.79	—
2008:			
Quarter Ended December 31	$ 20.93	$ 2.19	$ 0.090
Quarter Ended September 30	34.13	24.26	0.320
Quarter Ended June 30	36.79	33.54	0.380
Quarter Ended March 31	37.37	31.55	0.360

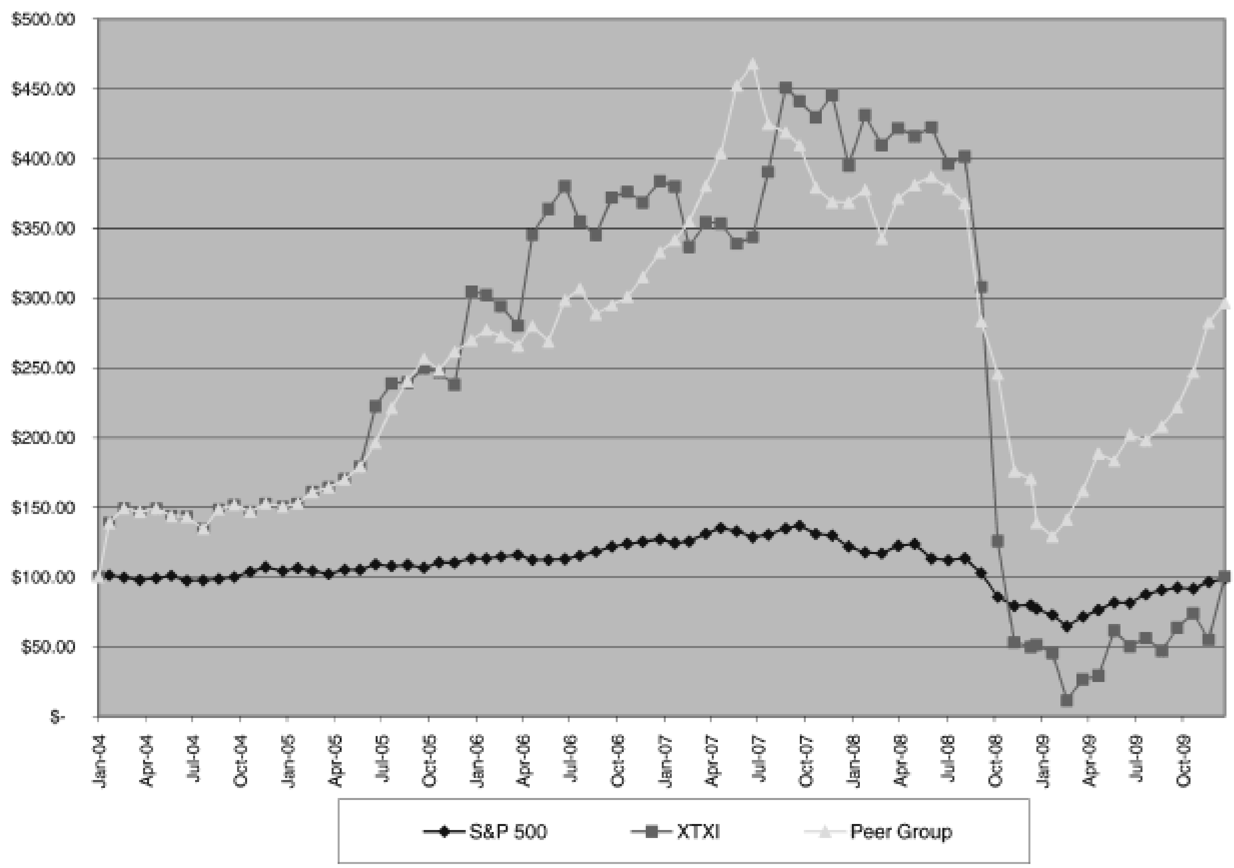
Historically, we have paid to our stockholders, on a quarterly basis, dividends equal to the cash we receive from our Partnership distributions, less reserves for expenses, future dividends and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner's 2.0% general partner interest; and
- reserves our board of directors believes prudent to maintain.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors deems relevant. Prior to 2009, we received quarterly distributions from the Partnership with the last distribution for the fourth quarter of 2008 received in February 2009. During 2009, the Partnership's ability to distribute available cash was contractually restricted by the terms of its credit facility due to its high leverage ratios and it ceased making distributions. Although the Partnership's new credit facility does not limit its ability to make distributions as long as the Partnership is not in default of its facility (and the indenture governing its senior unsecured notes requires it to meet a ratio test), any decision to resume cash distributions on its units and the amount of any such distributions would consider maintaining sufficient cash flow in excess of the distribution to continue to move the Partnership towards lower leverage ratios. The Partnership has established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA of less than 4.0 to 1.0, and the Partnership does not currently expect to resume cash distributions on its outstanding units until it achieves such a ratio of less than 4.5 to 1.0 (pro forma for any distribution). The Partnership will also consider general economic conditions and its outlook for business as it determines to pay any distribution. We do not anticipate making any future dividend payments until we begin receiving distributions from the Partnership again.

Performance Graph

The following graph sets forth the cumulative total stockholder return for our common stock, the Standard & Poor's 500 Stock Index, and a peer group of publicly traded partners of publicly traded limited partnerships in the Midstream natural gas, natural gas liquids and propane industries from January 12, 2004, the date of our initial public offering, through December 31, 2009. The chart assumes that $100 was invested on January 12, 2004, with dividends reinvested. The peer group includes Atlas Pipeline Holdings, L.P., Inergy Holdings, L.P., Enterprise GP Holdings, L.P., Alliance Holdings GP, L.P. and Magellan Midstream Holdings, L.P. (Inergy Holdings, L.P.'s initial public offering was in June 2005, Enterprise GP Holdings L.P.'s initial public offering was in August 2005, Atlas Pipeline Holdings, L.P.'s initial public offering was in July 2006, Alliance Holdings GP, L.P.'s initial public offering was in May 2006, and Magellan Midstream Holdings, L.P.'s initial public offering was in February 2006, and it has been assumed that these companies performed in accordance with the peer group average prior to such dates).



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

The following table sets forth selected historical financial and operating data of Crosstex Energy, Inc. as of and for the dates and periods indicated. The revised selected historical financial data are derived from the audited financial statements of Crosstex Energy, Inc. and have been revised to reflect 2009 asset disposition as discontinued operations and to move letter of credit fees to interest expense and from purchased gas expense. The summary historical financial and operating data include the results of operations, the south Louisiana processing assets beginning November 2005, the NTP beginning April 2006, the midstream assets acquired from Chief beginning June 2006 and other smaller acquisitions completed during 2006.

The table should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Crosstex Energy, Inc.				
	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Midstream	$ 1,453,346	$ 3,072,646	$ 2,380,224	$ 1,534,800	$ 1,212,864
Gas and NGL marketing activities	5,744	3,365	4,105	2,535	1,599
Total revenues	1,459,090	3,076,011	2,384,329	1,537,335	1,214,463
Operating costs and expenses:					
Purchased gas	1,147,868	2,768,225	2,124,503	1,378,979	1,154,345
Operating expenses	110,394	125,762	91,236	65,916	28,989
General and administrative	62,491	72,377	62,270	45,724	32,141
(Gain) loss on derivatives	(2,994)	(8,619)	(4,147)	(174)	10,399
Gain on sale of property	(666)	(947)	(1,024)	(1,936)	(8,289)
Impairments	2,894	30,177	—	—	—
Depreciation and amortization	119,162	107,652	83,361	56,410	15,168
Total operating costs and expenses	1,439,149	3,094,627	2,356,199	1,544,919	1,232,753
Operating income (loss)	19,941	(18,616)	28,130	(7,584)	(18,290)
Other income:					
Interest expense, net	(95,078)	(74,861)	(47,649)	(19,512)	(11,972)
Loss on extinguishment of debt	(4,669)	—	—	—	—
Other income	1,449	27,898	538	1,802	391
Total other income (expense)	(98,298)	(46,963)	(47,111)	(17,710)	(11,581)
Loss from continuing operations before income taxes and gain on issuance of Partnership units	(78,357)	(65,579)	(18,981)	(25,294)	(29,871)
Income tax benefit (provision)	6,020	1,375	(6,319)	(7,833)	(23,095)
Gain on issuance of Partnership units(1)	—	14,748	7,461	18,955	65,070
Income (loss) from continuing operations before cumulative effect of change in accounting principle, net of tax	(72,337)	(49,456)	(17,839)	(14,172)	12,104
Discontinued Operations:					
Income (loss) from discontinued operations-net of tax	(1,519)	21,466	26,817	17,429	41,684
Gain from sale of discontinued operations-net of tax	159,961	42,753	—	—	—
Discontinued operations-net of tax	158,442	64,219	26,817	17,429	41,684
Net income (loss) before cumulative effect of change in accounting principle	86,105	14,763	8,978	3,257	53,788
Cumulative effect of change in accounting principle	—	—	—	170	—
Net income (loss)	86,105	14,763	8,978	3,427	53,788
Less: Interest of non-controlling partners in the Partnership's net income (loss):					
Interest of non-controlling partners in the Partnership's continuing operations	(48,069)	(55,704)	(22,331)	(24,881)	(24,885)
Interest of non-controlling partners in the Partnership's discontinued operations	(1,137)	15,454	19,133	11,853	29,537

	Crosstex Energy, Inc.				
	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share data)				
Interest of non-controlling partners in the Partnership's gain on sale of discontinued operations	119,669	30,780	—	—	—
Total interest of non-controlling partners in the Partnership's net income (loss)	70,463	(9,470)	(3,198)	(13,028)	4,652
Net income attributable to Crosstex Energy, Inc.	$ 15,642	$ 24,233	$ 12,176	$ 16,455	$ 49,136
Net income per common share-basic(2)	$ 0.33	$ 0.52	$ 0.26	$ 0.39	$ 1.30
Net income per common share-diluted(2)	$ 0.33	$ 0.51	$ 0.26	$ 0.39	$ 1.26
Dividends per share(2)(3):					
Common	$ 0.09	$ 1.32	$ 0.91	$ 0.807	$ 0.563
Balance Sheet Data (end of period):					
Working capital surplus (deficit)	$ (41,791)	$ (20,431)	$ (39,330)	$ (70,091)	$ 4,872
Property and equipment, net	1,280,197	1,528,490	1,426,546	1,107,242	668,632
Total assets	2,080,233	2,546,743	2,602,829	2,206,698	1,445,325
Long-term debt	873,702	1,263,706	1,223,118	987,130	522,650
Interest of non-controlling partners in the Partnership	587,624	522,961	489,034	391,103	264,726
Stockholders' equity	815,910	738,390	246,366	279,413	111,247
Cash Flow Data:					
Net cash flow provided by (used in (4)):					
Operating activities	$ 78,850	$ 170,154	$ 112,578	$ 113,839	$ 12,842
Investing activities	379,874	(186,768)	(411,382)	(885,825)	(614,822)
Financing activities	(461,980)	22,720	296,022	769,717	592,365
Other Financial Data:					
Gross margin(5)	$ 311,222	$ 307,786	$ 259,826	$ 158,356	$ 60,118
Operating Data:					
Pipeline throughput (MMBtu/d)	2,040,000	2,002,000	1,555,000	845,000	582,000
Natural gas processed (MMBtu/d)(6)	1,235,000	1,608,000	1,835,000	1,817,000	1,707,000
Producer services (MMBtu/d)	75,000	85,000	94,000	138,000	111,010

(1) We recognized gains of $14.7 million in 2008, $7.5 million in 2007, $19.0 million in 2006 and $65.1 million in 2005 as a result of the Partnership issuing additional units in public offerings at prices per unit greater than our equivalent carrying value.

(2) Per share amounts have been adjusted for the three-for-one stock split effected in December 2006.

(3) Dividends paid.

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

(5) Gross margin is defined as revenue, including Gas and NGL marketing activities, less related cost of purchased gas.

(6) Processed volumes during 2005 include a daily average for the south Louisiana processing plants for November 2005 and December 2005, the two-month period these assets were operated by the Partnership.

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

Crosstex Energy, Inc. is a Delaware corporation formed on April 28, 2000 to engage in the gathering, transmission, processing and marketing of natural gas and NGLs through its subsidiaries. On July 12, 2002, we formed Crosstex Energy, L.P., a Delaware limited partnership, to acquire indirectly substantially all of the assets, liabilities and operations of its predecessor, Crosstex Energy Services, Ltd. Our assets consist almost exclusively of partnership interests in Crosstex Energy, L.P., a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and NGLs. These partnership interests consist of (i) 16,414,830 common units, representing approximately 33% of the limited partner interests in Crosstex Energy, L.P. as of December 31, 2009 (representing 25% of the limited partner interest as of January 31, 2010 after the Partnership's issuance of Series A convertible preferred units) and (ii) 100% ownership interest in Crosstex Energy GP, L.P., the general partner of Crosstex Energy, L.P., which owns a 2.0% general partner interest and all of the incentive distribution rights in Crosstex Energy, L.P.

Our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. The Partnership is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership's business or to provide for future distributions.

The incentive distribution rights entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received \$0.25 for that quarter, 23.0% of all cash distributed after each unit has received \$0.3125 for that quarter, and 48.0% of all cash distributed after each unit has received \$0.375 for that quarter.

Prior to 2009, we received quarterly distributions from the Partnership with the last distribution for the fourth quarter of 2008 received in February 2009. During 2009, the Partnership's ability to distribute available cash was contractually restricted by the terms of its credit facility due to its high leverage ratios and it ceased making distributions. Although the Partnership's new credit facility should not limit its ability to make distributions during 2010 and in the future, any decision to resume cash distributions on its units and the amount of any such distributions would consider maintaining sufficient cash flow in excess of the distribution to continue to move the Partnership towards lower leverage ratios. The Partnership has established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA of less than 4.0 to 1.0, and the Partnership does not currently expect to resume cash distributions on its outstanding units until it achieves such a ratio of less than 4.5 to 1.0 (pro forma for any distribution). The Partnership will also consider general economic conditions and its outlook for business as it determines to pay any distribution.

Since our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own, we do not expect to receive any cash flows until the Partnership is able to improve its leverage ratio and begin making distributions again. As of December 31, 2009, we have \$9.9 million of cash (excluding cash held by the Partnership) which we expect to be sufficient to pay our expenses and federal income taxes and to fund our general partner contributions over the next several years based on our forecasted cash flows. We do not anticipate making any future dividend payments until we begin receiving distributions from the Partnership again.

Since we control the general partner interest in the Partnership, we reflect our ownership interest in the Partnership on a consolidated basis, which means that our financial results are combined with the Partnership's financial results and the results of our other subsidiaries. The interest owned by non-controlling partners' share of income is reflected separately in our results of operations. We have no separate operating activities apart from those conducted by the Partnership, and our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. Our consolidated results of operations are derived from the results of operations of the Partnership and also include our gains on the issuance of units in the Partnership, deferred taxes, interest of non-controlling partners in the Partnership's net income, interest income (expense) and general and administrative expenses not reflected in the Partnership's results of operation. Accordingly, the discussion of our financial position and results of operations in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" primarily reflects the operating activities and results of operations of the Partnership.

Historically, the Partnership has operated two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. In February 2009, the Oklahoma assets were sold; in August 2009 the Alabama, Mississippi and south Texas Midstream properties were sold; and in October 2009 the Treating assets were sold, as more fully described under "Recent Developments and Business Strategy." The Partnership's primary focus for continuing operations is on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, which constitute one reporting segment of midstream activity. Currently, the geographic focus is in the north Texas Barnett shale area and in Louisiana. The Partnership focuses on gross margin to manage its operations because its business is generally to purchase and resell natural gas for a margin, or to gather, process, transport or market natural gas or NGLs for a fee. The Partnership buys and sells most of its natural gas at a fixed relationship to the relevant index price. In addition, the Partnership receives certain fees for processing based on a percentage of the liquids produced and enters into hedge contracts for its expected share of the liquids produced to protect margins from changes in liquids prices.

The Partnership's margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through its pipeline systems, processed at its processing facilities and the volumes of NGLs handled at its fractionation facilities. The Partnership generates revenues from four primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems it owns;
- processing natural gas at its processing plants and fractionating and marketing the recovered NGLs;
- providing compression services; and
- providing off-system marketing services for producers.

The Partnership generally gathers or transports gas owned by others through its facilities for a fee, or it buys 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 transports and resells the natural gas. The Partnership attempts to execute all purchases and sales substantially concurrently, or it enters into a future delivery obligation, thereby establishing the basis for the margin it will receive for each natural gas transaction. Gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. The Partnership is also party to certain long-term gas sales commitments that it satisfies through supplies purchased under long-term gas purchase agreements. When the Partnership enters into those arrangements, its sales obligations generally match its purchase obligations. However, over time the supplies that are under contract may decline due to reduced drilling or other causes and the Partnership 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 the Partnership's purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, the Partnership has 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 it captures the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as its margin. Changes in the basis spread can increase or decrease margins (or even be negative at times).

The Partnership realizes margins from processing services primarily through three different contract arrangements: processing margins (margin), percentage of liquids (POL) or fee based. Under the margin contract arrangements the Partnership's margins are higher during periods of high liquid prices relative to natural gas prices. Gross margin results under a POL contract are impacted only by the value of the liquids produced. Under fee based contracts the Partnership's margins are driven by throughput volume. See "—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 and associated transportation and communication costs, property insurance, ad valorem taxes, repair and maintenance expenses, measurement 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 moved through the asset.

Recent Developments and Business Strategy

From the Partnership's inception in 2002 until the second half of 2008, its long-term strategy had been to increase distributable cash flow per unit by accomplishing economies of scale through new construction or expansion in core operating areas and making accretive acquisitions of assets that are essential to the production, transportation and marketing of natural gas and NGLs. In response to the volatility in the commodity and capital markets over the last 18 months and other events, including the substantial decline in commodity prices, the Partnership adjusted its business strategy in the fourth quarter 2008 and in 2009 to focus on maximizing liquidity, improving its balance sheet through debt reduction and other methods, maintaining a stable asset base, improving the profitability of its assets by increasing their utilization while controlling costs and reducing capital expenditures. Consistent with this strategy, the Partnership divested non-core assets since October 2008 for aggregate sale proceeds of $618.7 million and substantially reduced outstanding debt. It plans to continue the focus on (i) improving existing system profitability, (ii) continuing to improve the balance sheet and financial flexibility and (iii) pursuing strategic acquisitions and undertaking selective construction and expansion opportunities. The Partnership is successfully executing its plan as highlighted by the following accomplishments:

- *Sold Non-Core Assets.* The Partnership sold $618.7 million of non-core assets and repaid approximately $500 million in long-term indebtedness from the sales proceeds over the last 15 months. In November 2008 the Partnership sold its 12.4% interest in the Seminole gas processing plant for $85.0 million. In the first quarter of 2009, the Partnership sold the Arkoma system for approximately $10.7 million. In August 2009, it sold the midstream assets in Alabama, Mississippi and south Texas for approximately $217.6 million. In addition, in October 2009, the Partnership sold its natural gas treating business for $265.4 million. The Partnership also sold its east Texas midstream assets on January 15, 2010 for $40.0 million.

- *Reduced Capital Expenditures.* The Partnership reduced capital expenditures from over $275.6 million for 2008 to $101.4 million in 2009 and focused the capital projects spending on lower risk projects with higher expected returns.

- *Reduced Operating and General and Administrative Expenses.* The Partnership reduced operating expenses from continuing operations to $110.4 million for the year ended December 31, 2009 from $125.8 million for the year December 31, 2008 and general and administrative expenses from continuing operations to $59.9 million for the year ended December 31, 2009 from $68.9 million for the year December 31, 2008 by reducing staffing and controlling costs. General and administrative expenses for the year ended December 31, 2009 also include non-recurring costs totaling $4.4 million associated with severance payments, lease termination costs and bad debt expense due to the SemStream, L.P. bankruptcy.

- *Acquired Certain Assets in Our Core Areas.* The Partnership acquired the Eunice NGL processing plant and fractionation facility in October 2009 for $23.5 million in cash and the assumption of $18.1 million in debt. It originally acquired the contract rights associated with the Eunice plant as part of the south Louisiana acquisition in November 2005 and operated and managed the plant under an operating lease with an unaffiliated third party prior to the recent acquisition. This acquisition will eliminate lease obligations of $12.2 million per year. The Partnership also acquired the Intracoastal Pipeline located in southern Louisiana for approximately $10.3 million in December 2009. Both of these acquisitions were designed to enhance the NGL business.

- *Sale of Preferred Units.* On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions. The 14,705,882 preferred units are convertible at any time into common units of the Partnership 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 after three years if (i) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 days ending on two trading days before the date on which the notice is delivered of such conversion, and (ii) the average daily trading volume of common units must have exceeded 250,000 common units for 20 out of the trailing 30 trading days ending on two trading days before the date on which the notice is delivered of such conversion. The preferred units are not redeemable but will pay 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. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if the Partnership pays a cash distribution on common units.

- *Issuance of Senior Unsecured Notes.* On February 10, 2010, the Partnership issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes due 2018 at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under its new credit facility discussed below, were used to repay in full amounts outstanding under its existing bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with its existing credit facility. The notes are unsecured and unconditionally guaranteed on a senior basis by certain of our direct and indirect subsidiaries, including substantially all of our current subsidiaries. Interest payments will be paid semi-annually in arrears starting in August 2010. The Partnership has the option to redeem all or a portion of the notes at any time on or after February 15, 2014, at the specified redemption prices. Prior to February 15, 2014, it may redeem the notes, in whole or in part, at a "make-whole" redemption price. In addition, the Partnership may redeem up to 35% of the notes prior to February 15, 2013 with the cash proceeds from certain equity offerings.

- *New Credit Facility.* In February 2010, the Partnership amended and restated its existing secured bank credit facility with a new syndicated secured bank credit facility which will be guaranteed by substantially all of the Partnership's subsidiaries. The size of the new credit facility is $420.0 million and matures in February 2014. Obligations under the new credit facility will be secured by first priority liens on substantially all of the Partnership's 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 the equity interests in substantially all of the Partnership's subsidiaries. Under the new credit facility, borrowings will bear interest at the Partnership's option at the British Bankers Association LIBOR Rate plus an applicable margin, or 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, in each case plus an applicable margin. It will pay a per annum fee on all letters of credit issued under the new credit facility, and will pay a commitment fee of 0.50% per annum on the unused availability under the new credit facility. The letter of credit fee and the applicable margins for its interest rate vary quarterly based on the Partnership's leverage ratio.

Acquisitions and Expansion Prior to 2009

The Partnership grew significantly through asset purchases and construction and expansion projects in years prior to 2009. As discussed above, it disposed of certain assets during late 2008 and 2009 to refocus its business on the gathering, processing, transmission and marketing of natural gas and NGLs in the north Texas Barnett Shale area and in Louisiana. These acquisitions and dispositions create many of the major differences when comparing operating results from one period to another. The most significant asset purchase since January 2006 was the acquisition of midstream assets from Chief in June 2006. In addition, internal expansion projects in north Texas and Louisiana have contributed to the increase in business during 2006, 2007, 2008 and 2009. The Partnership also acquired treating assets during 2006 that were included in the sale of its Treating business in 2009 as discussed above.

On June 29, 2006, the Partnership expanded operations in the north Texas area through the acquisition of the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. Immediately following the closing of the Chief acquisition, it began expanding its north Texas pipeline gathering system. The continued expansion of the Partnership's north Texas gathering systems to handle the growing production in the Barnett Shale was one of its core areas for internal growth during 2006, 2007, 2008 and 2009. Since the date of the acquisition through December 31, 2009, the Partnership has expanded its gathering system, connected in excess of 500 new wells to its north Texas gathering system and significantly increased the productive acreage dedicated to its systems. As of December 31, 2009, total capacity on its north Texas gathering system was approximately 1,100 MMcf/d and total throughput was approximately 793,000 MMBtu/d for the year ended December 31, 2009. Since 2006, the Partnership has constructed three gas processing plants with a total processing capacity in the Barnett Shale of 280 MMcf/d, including its Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, its Azle plant, which is a 50 MMcf/d cryogenic processing plant and its Goforth plant, which is a 30 MMcf/d processing plant. Total processing throughput averaged 219,000 MMBtu/d for the year ended December 31, 2009.

In 2007, the Partnership extended its Crosstex LIG system to the north to reach additional productive areas in the developing natural gas fields south of Shreveport, Louisiana, primarily in the Cotton Valley formation. This extension, referred to as the north Louisiana expansion, consists of 63 miles of 24" mainline with 9 miles of gathering lateral pipeline. The Partnership's north Louisiana expansion bisects the developing Haynesville Shale gas play in north Louisiana. The north Louisiana expansion was operating at near capacity during 2008 as Haynesville gas was beginning to develop so the Partnership added 35 MMcf/d of capacity by adding compression during the third quarter of 2008 bringing the total capacity of the north Louisiana expansion to approximately 275 MMcf/d. The Partnership continued the expansion of its north Louisiana system during 2009 increasing capacity by 100 MMcf/d in July 2009 by adding compression. It increased capacity by another 35 MMcf/d with a new interconnect into an interstate pipeline in December 2009 and bringing total capacity to 410 MMcf/d by the end of 2009. The Partnership has long-term firm transportation agreements subscribing to all of the incremental capacity added during 2009. In addition, the Partnership added compression during 2009 between the southern portion of its Crosstex LIG system and the northern expansion of its Crosstex LIG system which increased the capacity to bring gas from the north to its markets in the south to 145 MMcf/d. Interconnects on the north Louisiana expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission, Trunkline Gas and Tennessee Gas Pipeline.

Impact of Federal Income Taxes

Crosstex Energy, Inc. is a corporation for federal income tax purposes. As such, our federal taxable income is subject to tax at a maximum rate of 35.0% under current law. We expect to have taxable income allocated to us as a result of our investment in the Partnership's units, particularly because of remedial allocations that will be made among the unitholders. Taxable income allocated to us by the Partnership will increase over the years as the results of operation increase and as the ratio of income to distributions increases for all of the unitholders.

As of December 31, 2009 we have a net operating loss carry forward of $47.5 million for federal income taxes and state loss carry forwards of $30.1 million. We believe it is more likely than not that our future results of operations will generate sufficient taxable income to utilize these net operating loss carry forwards before they expire. Once these net operating loss carry forwards are fully utilized, we will have to pay tax on our federal taxable income at a maximum rate of 35.0% under current law.

Our use of this net operating loss carry forward will be limited if there is a greater than 50.0% change in our stock ownership over a three year period.

Commodity Price Risk

The Partnership's business is subject to significant risks due to fluctuations in commodity prices. Its exposure to these risks is primarily in the gas processing component of its business. A large percentage of the processing fees are realized under POL contracts that are directly impacted by the market price of NGLs. It also realizes processing gross margins under margin contracts. These settlements are impacted by the relationship between NGL prices and the underlying natural gas prices, which is also referred to as the fractionation spread.

A significant volume of inlet gas at the Partnership's south Louisiana and north Texas processing plants is settled under POL agreements. The POL fees are denominated in the form of a share of the liquids extracted and the Partnership is not responsible for the fuel or shrink associated with processing. Therefore, fee revenue under a POL agreement is directly impacted by NGL prices, and the decline of these prices in 2008 and early 2009, contributed to a significant decline in gross margin from processing. The Partnership has a number of fractionation margin contracts on its Plaquemine and Gibson processing plants that expose it to the fractionation spread. Under these margin contracts its gross margin is based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state ("shrink") and the cost of fuel to extract during processing. During the last half of 2008 and early 2009, the fractionation spread narrowed significantly as the value of NGLs decreased more than the value of the gas and fuel associated with the processed gas. Thus the gross margin realized under these margin contracts was negatively impacted due to the commodity price environment. Such a decline may negatively impact its gross margin in the future if such declines continue.

The Partnership is also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of its gathering and transportation services. Approximately 8.0% of the natural gas it markets 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, resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices.

See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk" for additional information on Commodity Price Risk.

Results of Operations

Set forth in the table below is certain financial and operating data for the periods indicated.

	Years Ended December 31,		
	2009	2008	2007
	(Dollars in millions)		
Midstream revenues	$ 1,453.3	$ 3,072.6	$ 2,380.2
Purchased gas	(1,147.8)	(2,768.2)	(2,124.5)
Gas and NGL marketing activities	5.7	3.4	4.1
Total gross margin	$ 311.2	$ 307.8	$ 259.8
Volumes (MMBtu/d):			
Gathering and transportation	2,040,000	2,002,000	1,555,000
Processing	1,235,000	1,608,000	1,835,000
Producer services	75,000	85,000	94,000

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Gross Margin and Gas and NGL Marketing Activities. Midstream gross margin was $311.2 million for the year ended December 31, 2009 compared to $307.8 million for the year ended December 31, 2008, an increase of $3.4 million, or 1.1%. The increase was primarily due to higher margins on gathering and transmission throughput volume. These increases were partially offset by gross margin declines in the processing business due to a less favorable NGL market. Gas and NGL marketing activities increased for the comparative periods by approximately $2.4 million primarily due to an improved fee structure and an increase in activity in the liquids marketing business.

The LIG gathering and transmission system contributed gross margin growth of $14.0 million for the twelve months ended December 31, 2009 over the same period in 2008 primarily due to improved pricing and higher volumes on the northern part of the system offsetting a decrease in sales volume at southern delivery points. The north Texas region contributed $13.9 million of gross margin growth for the comparative periods primarily due to increased volume on the gathering systems. The gross margin increase contributed by the north Texas region was partially offset by an increase in purchased gas costs of $3.7 million related to the arbitration award to Denbury discussed under "Contingencies." The weaker processing environment contributed to a significant decline in the gross margins for processing plants in Louisiana for the twelve months ended December 31, 2009. Overall the plants in the region reported a margin decrease of approximately $15.1 million. The primary contributors to this decrease were the Gibson, Plaquemine and Blue Water processing plants which had gross margin declines of $9.8 million, $7.6 million and $3.5 million, respectively. These declines were partially offset by an increase of approximately $8.3 million in the fractionation and liquids marketing activities in the region. The Arkoma system, which was sold in April 2009, created a negative gross margin variance of $4.0 million when compared to the same period in 2008. The Crosstex Pipeline system in east Texas had a gross margin decline of $1.7 million primarily due to a decline in throughput volumes.

Operating Expenses. Operating expenses were $110.4 million for the year ended December 31, 2009 compared to $125.8 million for the year ended December 31, 2008, a decrease of $15.4 million, or 12.2%, resulting primarily from initiatives undertaken in late 2008 and early 2009 to reduce expenses.

General and Administrative Expenses. General and administrative expenses were $62.5 million for the year ended December 31, 2009 compared to $72.4 million for the year ended December 31, 2008, a decrease of $9.9 million, or 13.7%. The decrease is a result of strategic initiatives undertaken to reduce expenses and primarily relate to workforce reductions. The 2009 amount includes $4.4 million of non-recurring costs consisting of $3.1 million of severance payments, $0.8 million of lease termination costs and $0.5 million of bad debt expense due to the SemStream, L.P. bankruptcy.

Gain/Loss on Derivatives. Gains on derivatives were $3.0 million for the year ended December 31, 2009 compared to gains of $8.6 million for the year ended December 31, 2008. The derivative transaction types contributing to the net gain are as follows (in millions):

	Years Ended December 31,			
	2009		2008	
	Total	Realized	Total	Realized
(Gain)/Loss on Derivatives:				
Basis swaps	$ (4.4)	$ (2.5)	$ (8.7)	$ (8.8)
Processing margin hedges	1.4	(2.2)	(3.6)	(3.6)
Storage	(0.3)	(1.1)	(0.7)	(0.1)
Third-party on-system swaps	(0.1)	(0.3)	(0.6)	(0.8)
Other	0.1	—	(0.1)	—
	(3.3)	(6.1)	(13.7)	(13.3)
Derivative gains included in income from discontinued operations	0.3	0.5	5.1	5.4
	$ (3.0)	$ (5.6)	$ (8.6)	$ (7.9)

Impairments. During the year ended December 31, 2009, the Partnership had impairment expense of $2.9 million compared to $30.2 million for the year ended December 31, 2008. During 2009, impairments totaling $2.9 million were taken on the Bear Creek processing plant and the Vermillion treating plant to bring the fair value of the plants to a marketable value for these idle assets. The impairment expense during 2008 is comprised of:

- $17.8 million related to the Blue Water gas processing plant located in south Louisiana — The impairment on the Partnership's 59.27% interest in the Blue Water gas processing plant was recognized because the pipeline company which owns the offshore Blue Water system and supplies gas to the Blue Water plant reversed the flow of the gas on its pipeline in early January 2009 thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system. As of January 2009, an alternative source of new gas for the Blue Water plant had not been found so the plant ceased operation from January 2009 until November 2009. An impairment of $17.8 million was recognized for the carrying amount of the plant in excess of its estimated fair value as of December 31, 2008.

- $5.7 million related to goodwill — It was determined that the carrying amount of goodwill attributable to the Midstream segment was impaired because of the significant decline in Midstream operations due to negative impacts on cash flows caused by the significant declines in natural gas and NGL prices during the last half of 2008 coupled with the global economic decline.

- $4.1 million related to leasehold improvements — The Partnership had planned to relocate its corporate headquarters during 2008 to a larger office facility. The Partnership had leased office space and was close to completing the renovation of this office space when the global economic decline began impacting operations in October 2008. On December 31, 2008, the decision was made to cancel the new office lease and not relocate the corporate offices from its existing office location. The impairment relates to the leasehold improvements on the office space for the cancelled lease.

- $2.6 million related to the Arkoma gathering system — The impairment on the Arkoma gathering system was recognized because the asset was sold in February 2009 for $10.7 million and the carrying amount of the plant exceeded the sale price by approximately $2.6 million.

Depreciation and Amortization. Depreciation and amortization expenses were $119.2 million for the year ended December 31, 2009 compared to $107.7 million for the year ended December 31, 2008, an increase of $11.5 million, or 10.7%, resulting primarily from growth and expansion in the NTP, NTG and north Louisiana areas.

Interest Expense. Interest expense was $95.1 million for the year ended December 31, 2009 compared to $74.9 million for the year ended December 31, 2008, an increase of 20.2 million, or 27.0%. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2009	2008
Senior notes	$ 28.3	$ 22.5
PIK	4.9	—
Credit facility	30.7	20.8
Series B secured note	0.4	—
Capitalized interest	(1.1)	(2.7)
Mark to market interest rate swaps	(0.8)	22.1
Realized interest rate swaps	19.0	4.6
Interest income	(0.2)	(0.4)
Amortization of debt issue cost	7.6	2.9
Other	6.3	5.1
Total	$ 95.1	$ 74.9

Loss on Extinguishment of Debt. The Partnership recognized a loss on extinguishment of debt during the year ended December 31, 2009 of $4.7 million due to the February 2009 amendment to the senior secured notes agreement. The modifications to this agreement pursuant to this amendment were substantive as defined in FASB ASC 470-50 and were accounted for as the extinguishment of the old debt and the creation of new debt. As a result, the unamortized costs associated with the senior secured notes prior to the amendment as well as the fees paid to the senior secured lenders for the February 2009 amendment were expensed during the year ended December 31, 2009.

Other Income. Other income was $1.4 million for the year ended December 31, 2009 compared to $27.9 million for the year ended December 31, 2008. In November 2008, the Partnership sold a contract right for firm transportation capacity on a third party pipeline to an unaffiliated third party for $20.0 million. The entire amount of such proceeds is reflected in other income because the Partnership had no basis in this contract right. In February 2008, the Partnership recorded $7.0 million from the settlement of disputed liabilities that were assumed with an acquisition.

Income Taxes. We provide for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. Income tax benefit was $6.0 million and $1.4 million for the years ended December 31, 2009 and 2008, respectively.

Gain on Issuance of Units of the Partnership. As a result of the Partnership issuing common units in April 2008 to unrelated parties at a price per unit greater than our equivalent carrying value, our share of net assets of the Partnership increased by $14.7 million and we recognized a gain on issuance of such units.

Discontinued Operations. The Partnership sold the following non-strategic assets over the past year and used the proceeds from such sales to repay long-term indebtedness:

Assets	Date of Sale
12.4% interest in the Seminole Gas Processing Plant	November 2008
Oklahoma assets (Arkoma system)	February 2009
Alabama, Mississippi and south Texas assets	August 2009
Treating assets	October 2009

In accordance with FASB ASC 360-10-05-4, the results of operations related to each of the assets listed above (except the Arkoma assets which were immaterial to the financial statement presentations) are presented in income from discontinued operations for the comparative periods in the statements of operations. Revenues, operating expenses, general and administrative expenses associated directly to the assets sold, depreciation and amortization, allocated Texas margin tax and allocated interest are reflected in the income from discontinued operations. During the year ended December 31, 2009, the Partnership expensed $4.3 million of unamortized debt issuance costs associated with the bank credit facility and the senior secured notes due to the repayments in borrowings of $316.3 million and $153.8 million, respectively, from proceeds of the Alabama, Mississippi and south Texas assets and Treating assets dispositions. In addition, we incurred make-whole interest and call premiums of $5.2 million in the year ended December 31, 2009 to the holders of the senior secured notes due to the call premiums on the repayments. These additional interest costs are included in discontinued operations for the year ended December 31, 2009. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are the components of revenues and earnings from discontinued operations and operating data (dollars in millions):

	Year Ended December 31,	
	2009	2008
Midstream revenues	$ 368.1	$ 1,766.1
Treating revenues	$ 45.5	$ 73.5
Income (loss) from discontinued operations, net of tax	$ (1.5)	$ 21.5
Gain from sale of discontinued operations, net of tax	$ 160.0	$ 42.8
Gathering and Transmission Volumes (MMBtu/d)	564,000	617,000
Processing Volumes (MMBtu/d)	191,000	204,000

Interest of Non-Controlling Partners in the Partnership's Net Income (Loss) from Continuing Operations. The interest of non-controlling partners in the Partnership's net loss was $48.1 million for the year ended December 31, 2009 compared to a net loss of $55.7 million for the year ended December 31, 2008 due to the changes shown in the following summary (in millions):

	Years Ended December 31,	
	2009	2008
Net loss from continuing operations for the Partnership	$ (77.5)	$ (63.7)
(Income) allocation to CEI for the general partner incentive distribution	—	(30.8)
Stock-based compensation costs allocated to CEI for its stock options and restricted stock granted to Partnership officers, employees and directors	3.0	4.7
Loss allocation to CEI for its 2% general partner share of Partnership loss	1.5	1.2
Net loss allocable to limited partners	(73.0)	(88.6)
Less: CEI's share of net (income) loss allocable to limited partners	24.9	32.6
Plus: Non-controlling partners' share of net income in Denton County Joint Venture	—	0.3
Non-controlling partners' share of Partnership net loss from continuing operations	$ (48.1)	$ (55.7)

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Gross Margin and Gas and NGL Marketing Activities. Midstream gross margin was $307.8 million for the year ended December 31, 2008 compared to $259.8 million for the year ended December 31, 2007, an increase of $48.0 million, or 18.5%. The increase was primarily due to system expansion projects and increased throughput on the Partnership's gathering and transmission systems. These increases were partially offset by margin decreases in the processing business due to a less favorable NGL market and operating downtime resulting from the impact of hurricanes in the last half of the year. Gas and NGL marketing activities decreased for the comparative periods by approximately $0.7 million.

System expansion in the north Texas region and increased throughput on the NTP contributed $58.9 million of gross margin growth for the year ended December 31, 2008 over the same period in 2007. The Partnership's gathering systems in the region and NTP accounted for $41.3 million and $9.1 million of this increase, respectively. The Partnership's processing facilities in the region contributed an additional $8.5 million of gross margin increase. System expansion and volume increases on the LIG system contributed margin growth of $8.2 million during the year ended December 31, 2008 over the same period in 2007. Processing plants in Louisiana experienced a margin decline of $20.2 million for the comparative twelve-month period in 2008 due to a less favorable NGL processing environment in the last half of the year and business interruptions resulting from the impact of hurricanes along the Gulf Coast.

The Partnership's processing and gathering systems were negatively impacted by events beyond our control during the third quarter that had a significant effect on gross margin results for the year ended December 31, 2008. Hurricanes Gustav and Ike came ashore along the Gulf coast in September 2008. The Partnership estimates that these storms resulted in approximately $22.9 million gross margin decrease for the year. The lost margin was primarily experienced at gas processing facilities along the Gulf Coast. However, processing facilities further inland in Louisiana and north Texas were indirectly impacted due to disruption in the NGL markets. In addition, approximately $0.9 million in gross margin was lost at the Sabine Pass plant in August 2008 due to downtime from fire damage. The fire occurred during an attempt to bring the plant back on line following tropical storm Edouard.

Operating Expenses. Operating expenses were $125.8 million for the year ended December 31, 2008 compared to $91.2 million for the year ended December 31, 2007, an increase of $34.5 million, or 37.8%, resulting primarily from growth and expansion in the NTP, NTG, north Louisiana and east Texas areas. The increase is primarily attributable to the following factors:

- Contractor services and labor costs increased $12.3 million;
- Chemicals and materials increased $6.2 million;
- Equipment rental increased $5.8 million;
- Ad valorem taxes increased $2.2 million; and
- Technical services increased $0.7 million.

General and Administrative Expenses. General and administrative expenses were $72.4 million for the year ended December 31, 2008 compared to $62.3 million for the year ended December 31, 2007, an increase of $10.1 million, or 16.2%. The increase is primarily attributable to the following factors:

- $5.5 million increase in rental expense resulting primarily from additional office rent and including $3.4 million related to lease termination fees for the cancelled relocation of our corporate headquarters;
- $3.1 million increase in bad debt expense due to the SemStream, L.P. bankruptcy;
- $1.8 million increase in professional fees and services; and
- $0.9 million decrease in stock-based compensation expense resulting primarily from the reduction of estimated performance-based restricted units and restricted shares.

Gain/Loss on Derivatives. Gains on derivatives were $8.6 million for the year ended December 31, 2008 compared to gains of $4.1 million for the year ended December 31, 2007. The derivative transaction types contributing to the net gain are as follows (in millions):

	Years Ended December 31,			
	2008		2007	
	Total	Realized	Total	Realized
(Gain) Loss on Derivatives:				
Basis swaps	$ (8.7)	$ (8.8)	$ (8.1)	$ (7.0)
Processing margin hedges	(3.6)	(3.6)	1.3	1.3
Storage	(0.7)	(0.1)	(0.5)	(1.6)
Third-party on-system swaps	(0.6)	(0.8)	(0.2)	(0.6)
Puts	—	—	0.8	—
Other	(0.1)	—	0.1	—
	(13.7)	(13.3)	(6.6)	(7.9)
Derivative gains included in income from discontinued operations	5.1	5.4	2.5	2.8
	$ (8.6)	$ (7.9)	$ (4.1)	$ (5.1)

Impairments. During the year ended December 31, 2008, the Partnership had an impairment expense of $30.2 million compared to no impairment expense for the year ended December 31, 2007. The 2008 impairment expense is described under "Year Ended December 31, 2009 Compared to Year Ended December 31, 2008."

Depreciation and Amortization. Depreciation and amortization expenses were $107.7 million for the year ended December 31, 2008 compared to $83.4 million for the year ended December 31, 2007, an increase of $24.3 million, or 29.1%. Depreciation and amortization increased $22.5 million due to the NTP, NTG and north Louisiana expansion project assets. Accelerated depreciation of the Dallas office leasehold due to the planned, but subsequently cancelled, relocation accounted for an increase between periods of $1.4 million.

Interest Expense. Interest expense was $74.9 million for the year ended December 31, 2008 compared to $47.6 million for the year ended December 31, 2007, an increase of $27.2 million, or 57.1%. The increase relates primarily to the negative impact of declining interest rates on the interest rate swaps. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2008	2007
Senior notes	$ 22.5	$ 23.0
Credit facility	20.8	24.8
Capitalized interest	(2.7)	(4.8)
Mark to market interest rate swaps	22.1	1.2
Realized interest rate swaps	4.6	(0.7)
Interest income	(0.4)	(1.2)
Amortization of debt issue cost	2.9	2.6
Other	5.1	2.7
Total	$ 74.9	$ 47.6

Other Income. Other income was $27.9 million for the year ended December 31, 2008 compared to $0.5 million for the year ended December 31, 2007. In November 2008, the Partnership sold a contract right for firm transportation capacity on a third party pipeline to an unaffiliated third party for $20.0 million. In February 2008, the Partnership recorded $7.0 million from the settlement of disputed liabilities that were assumed with an acquisition.

Income Taxes. We provide for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. We had an income tax benefit of $1.4 million in the year ended December 31, 2008. Income tax benefit of $1.4 million and income tax expense of $6.3 million was recorded for the years ended December 31, 2008 and 2007, respectively.

Gain on Issuance of Units of the Partnership. As a result of the Partnership issuing common units in April 2008 and December 2007 to unrelated parties at a price per unit greater than our equivalent carrying value, our share of net assets of the Partnership increased by $14.7 million and $7.5 million, respectively, and we recognized a gain on issuance of such units.

Discontinued Operations. Income from discontinued operations were $64.2 million for the year ended December 31, 2008 compared to $26.8 million for the year ended December 31, 2007. Discontinued operations includes income related to the Seminole gas processing plant disposed of in November 2008, income related to the Alabama, Mississippi and south Texas assets disposed of in August 2009 and income related to the Treating assets disposed of in October 2009. The reported income for the comparative periods has been recast to include 2009 dispositions in income from discontinued operations.

Interest of Non-Controlling Partners in the Partnership's Net Income (Loss) from Continuing Operations. The interest of non-controlling partners in the Partnership's net loss was $55.7 million for the year ended December 31, 2008 compared to a net loss of $22.3 million for the year ended December 31, 2007 due to the changes shown in the following summary (in millions):

	Years Ended December 31,	
	2008	**2007**
Net loss from continuing operations for the Partnership	$ (63.7)	$ (17.3)
(Income) allocation to CEI for the general partner incentive distribution	(30.8)	(24.8)
Stock-based compensation costs allocated to CEI for its stock options and restricted stock granted to Partnership officers, employees and directors	4.7	5.4
Loss allocation to CEI for its 2% general partner share of Partnership loss	1.2	0.7
Net loss allocable to limited partners	(88.6)	(36.0)
Less: CEI's share of net (income) loss allocable to limited partners	32.6	13.5
Plus: Non-controlling partners' share of net income in Denton County Joint Venture	0.3	0.2
Non-controlling partners' share of Partnership net loss from continuing operations	$ (55.7)	$ (22.3)

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 and a discussion of new accounting pronouncements.

Revenue Recognition and Commodity Risk Management. The Partnership recognizes revenue for sales or services at the time the natural gas or NGLs are delivered or at the time the service is performed. It 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 utilizes extensive estimation procedures to determine the sales and cost of gas purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. It uses 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. The Partnership believes that its accrual process for sales and purchases provides a reasonable estimate of such sales and purchases.

The Partnership engages in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas and natural gas liquids. The Partnership manages its 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 its future commitments and significantly reduce its risk to the movement in natural gas prices.

The Partnership uses derivatives to hedge against changes in cash flows related to product prices and interest rate risk, 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.

The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that it does not own. The Partnership refers to these activities as part of energy trading activities. In some cases, the Partnership earns an agency fee from the producer for arranging the marketing of the producer's natural gas. In other cases, the Partnership purchases the natural gas from the producer and enters into a sales contract with another party to sell the natural gas. The revenue and cost of sales for these activities are shown net in the statement of operations.

The Partnership manages its 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, the Partnership is subject to counter-party risk for both the physical and financial contracts. The Partnership's energy trading contracts qualify as derivatives, and it uses 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.

Sales of Securities by Subsidiaries. We recognize gains and losses in the consolidated statements of operations resulting from subsidiary sales of additional equity interest, including the Partnership's limited partnership units, to unrelated parties.

Impairment of Long-Lived Assets. In accordance with FASB ASC 360-10-05, the Partnership evaluates 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 the Partnership's long-lived assets has occurred, it must estimate the undiscounted cash flows attributable to the asset. The 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 to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas prices. Projections of gas 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 supply;
- the Partnership's ability to negotiate favorable sales agreements;
- the risks that natural gas exploration and production activities will not occur or be successful;
- the Partnership's dependence on certain significant customers, producers, and transporters of natural gas; and
- competition from other midstream companies, including major energy producers.

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

Depreciation Expense and Cost Capitalization. Our assets consist primarily of natural gas gathering pipelines, processing plants, and transmission pipelines owned by the Partnership. The Partnership capitalizes 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. The Partnership capitalizes the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred.

The Partnership generally computes depreciation using the straight-line method over the estimated useful life of the assets. Certain assets such as land, NGL line pack and natural gas 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, depreciation estimates may be reviewed 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 flow presented in liquidity discussions includes cash flow from discontinued operations.

Cash Flows from Operating Activities. Net cash provided by operating activities was $78.9 million, $170.2 million and $112.6 million for the years ended December 31, 2009, 2008 and 2007, respectively. Income before non-cash income and expenses and changes in working capital for 2009, 2008 and 2007 were as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Income before non-cash income and expenses	$ 87.3	$ 157.6	$ 136.4
Changes in working capital	(8.4)	12.5	(23.9)

The primary reason for the decreased cash flow from income before non-cash income and expenses of $70.3 million from 2008 to 2009 was increased interest expense of $19.4 million, decreased operating income of $11.2 million, decreased other income of $26.8 million, and decreased gain on derivatives of $7.2 million. The primary reason for the increased cash flow from income before non-cash income and expenses of $21.2 million from 2007 to 2008 was increased operating income from the Partnership's expansion in north Texas and north Louisiana during 2007 and 2008.

Cash Flows from Investing Activities. Net cash provided in investing activities was $379.9 million for the year ended December 31, 2009 primarily due to proceeds from asset sales. Net cash used in investing activities was $186.8 million and $411.4 million for the years ended December 31, 2008 and 2007, respectively. Cash flows from investing activities for the years ended December 31, 2009, 2008 and 2007 include proceeds from property sales of $503.9 million, $88.8 million and $3.1 million, respectively. Sales in 2009 primarily relate to the sale of the Partnership's Alabama, Mississippi, south Texas and Treating assets. Sales in 2008 relate to the sale of the Partnership's interest in the Seminole gas processing plant. The 2007 sales primarily relate to sales in inactive properties. Our primary investing activities for 2009, 2008 and 2007 were capital expenditures and acquisitions in the Partnership, net of accrued amounts, as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Growth capital expenditures	$ 90.5	$ 257.2	$ 403.7
Acquisitions and asset purchases	35.1	—	—
Maintenance capital expenditures	10.9	18.3	10.8
Total	$ 136.5	$ 275.5	$ 414.5

Net cash invested in Midstream assets was $123.8 million, $222.4 million and $385.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. Net cash invested in Treating assets was $11.1 million, $41.8 million and $23.5 million for the years ended December 31, 2009, 2008 and 2007 respectively. Net cash invested in other corporate assets was $1.6 million, $11.4 million and $5.2 million for the years ended December 31, 2009, 2008 and 2007 respectively.

Cash Flows from Financing Activities. The Partnership disposed of non-core assets and repaid outstanding debt which resulted in net cash used by financing activities of $462.0 million for the year ended December 31, 2009. Net cash provided in financing activities was $22.7 million and $296.0 million for the years ended December 31, 2008 and 2007, respectively. Our financing activities primarily relate to funding of capital expenditures and acquisitions in the Partnership. Our financings have primarily consisted of borrowings and repayments under the Partnership's bank credit facility, payments on senior secured notes, borrowings under capital lease obligations, equity offerings and senior note issuances in the Partnership in 2009, 2008 and 2007 as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Net borrowings under bank credit facility (1)	$ (254.4)	$ 50.0	$ 246.0
Senior secured note issuances (net of repayments) (2)	(163.2)	(9.4)	(9.4)
Common unit offerings	—	101.9	58.8
Net borrowings (payments) under capital lease obligations	(0.7)	23.9	3.6
Debt refinancing costs	(15.0)	(4.9)	(0.9)
Senior subordinated unit offerings	—	—	102.6

(1) Includes a $143.0 million and $173.3 million payment due to the sale of the Alabama, Mississippi and south Texas assets and the Treating assets.

(2) Includes a $69.0 million and $84.8 million payment due to sale of the Alabama, Mississippi and south Texas assets and the Treating assets.

Dividends to shareholders and distributions to non-controlling partners in the Partnership represent our primary use of cash in financing activities. Total cash distributions made during the last three years were as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Dividends to shareholders	$ 4.2	$ 62.0	$ 42.6
Non-controlling partners	7.6	63.2	39.0
Total	$ 11.8	$ 125.2	$ 81.6

In order to reduce our interest costs, the Partnership does 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. Changes in drafts payable for 2009, 2008 and 2007 were as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Decrease in drafts payable	$ (16.3)	$ (7.4)	$ (19.0)

Working Capital Deficit. We had a working capital deficit of $41.8 million as of December 31, 2009, primarily due to a net liability for the fair value of derivatives of $21.3 million and the current portion of long-term debt of $28.6 million related to the senior secured notes. The fair value of derivatives reflects the mark-to-market of such derivatives including a net current liability of $18.0 million related to interest rate swaps and a net current liability of $3.3 million related to commodity derivatives. In February 2010, the senior secured notes were repaid in full and the interest rate swaps were settled. Changes in working capital may fluctuate significantly between periods even though the Partnership's trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of its revenues are collected and a large volume of its gas 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 the Partnership strives to minimize natural gas and NGLs in inventory, these working inventory balances may fluctuate significantly from period to period due to operational reasons and due to changes in natural gas and NGL prices. Working capital also includes mark to market derivative assets and liabilities associated with commodity derivatives which may fluctuate significantly due the changes in natural gas and NGL prices and associated with interest rate swap derivatives which may fluctuate significantly due to changes in interest rates. The changes in working capital during the years ended December 31, 2009, 2008 and 2007 are due to the impact of the fluctuations discussed above.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2009 and 2008.

January 2010 Sale of Preferred Units. On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions. The 14,705,882 preferred units are convertible at any time into Partnership 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 after three years if (i) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 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 have exceeded 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 will pay 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. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if the Partnership pays a cash distribution on common units.

April 2008 Sale of Common Units. On April 9, 2008, the Partnership issued 3,333,334 common units in a private offering at $30.00 per unit, which represented an approximate 7% discount from the market price on such date. Net proceeds from the issuance, including our general partner contribution less expenses associated with the issuance, were approximately $102.0 million.

December 2007 Sale of Common Units. On December 19, 2007, the Partnership issued 1,800,000 common units at a price of $33.28 per unit for net proceeds of $57.6 million. We made a general partner contribution of $1.2 million in connection with the issuance to maintain our 2% general partner interest.

March 2007 Sale of Senior Subordinated Series D Units. On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests in a private offering for net proceeds of approximately $99.9 million. The senior subordinated series D units were issued at $25.80 per unit, which represented a discount of approximately 25% to the market value of common units on such date. The discount represented an underwriting discount plus the fact that the units would not receive a distribution nor be readily transferable for two years. We made a general partner contribution of $2.7 million in connection with this issuance to maintain our 2% general partner interest. The senior subordinated series D units automatically converted into common units on March 23, 2009 at a ratio of 1.05 common unit for a total issuance of 4,069,106 common units. The senior subordinated series D units were not entitled to distributions of available cash or allocations of net income/loss from the Partnership until March 23, 2009.

Capital Requirements of the Partnership. The Partnership reduced its capital expenditures for 2009 to improve liquidity. Total capital expenditures in the calendar year 2009 were less than $101.4 million. The Partnership utilized cash flow from operations and existing capacity under its bank credit facility to fund such expenditures. The Partnership's 2010 capital budget includes approximately $25.0 million of identified growth projects, and it expects to fund such expenditures with internally generated cash flow, with any excess cash flow applied toward debt, working capital or new projects. Although the Partnership expects to identify more growth projects during 2010 in addition to projects currently budgeted, it does not anticipate that its capital expenditures during 2010 will exceed $100.0 million.

Total Contractual Cash Obligations: A summary of the Partnership's total contractual cash obligations as of December 31, 2009 is as follows (in millions):

	Payments Due by Period						
	Total	2010	2011	2012	2013	2014	Thereafter
Long-Term Debt	$ 873.7	$ 28.6	$ 578.2	$ 93.0	$ 83.6	$ 67.4	$ 22.9
Interest Payable on Fixed Long-Term Debt Obligations	101.8	30.9	27.2	22.0	13.9	6.4	1.4
PIK Interest payable	19.0	—	19.0	—	—	—	—
Capital Lease Obligations	27.9	3.1	3.0	3.0	3.0	3.0	12.8
Operating Leases	56.6	15.9	12.1	9.3	6.2	4.7	8.4
Uncertain Tax Position Obligations	3.1	3.1	—	—	—	—	—
Total Contractual Obligations	$ 1,082.1	$ 81.6	$ 639.5	$ 127.3	$ 106.7	$ 81.5	$ 45.5

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 contractual obligations reflected above have been presented without adjustment for changes in obligations due to the February 2010 repayment in full of obligations associated with our existing credit facility and senior secured notes with proceeds from the new credit facility and the new senior unsecured notes.

Description of Indebtedness

As of December 31, 2009 and 2008, long-term debt consisted of the following (in millions):

	2009	2008
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2009 and 2008 were 6.75% and 3.9%, respectively	$ 529.6	$ 784.0
Senior secured notes (including PIK notes as defined below of $9.5 million), weighted average interest rates at December 31, 2009 and 2008 of 10.5% and 8.0%, respectively	326.0	479.7
Series B secured note assumed in the Eunice transaction, which bears interest at the rate of 9.5%	18.1	—
	873.7	1,263.7
Less current portion	(28.6)	(9.4)
Debt classified as long-term	$ 845.1	$ 1,254.3

The balance of the bank credit facility and senior secured notes was paid in full on February 10, 2010 with the proceeds from the new credit facility and the senior unsecured notes.

Credit Facility. As of December 31, 2009, the Partnership had a bank credit facility with a borrowing capacity of $859.9 million that matures in June 2011. As of December 31, 2009, $683.0 million was outstanding under the bank credit facility, including $153.4 million of letters of credit, leaving approximately $176.9 million available for future borrowing.

New Credit Facility. In February 2010, the Partnership amended and restated its existing secured bank credit facility with a new syndicated secured bank credit facility. The new credit facility has a borrowing capacity of $420.0 million and matures in February 2014. Net proceeds from the new credit facility along with net proceeds from the senior unsecured notes were used to, among other things, repay the bank credit facility and the senior secured notes.

The new credit facility will be guaranteed by substantially all of the Partnership's subsidiaries. Obligations under the new credit facility will be secured by first priority liens on substantially all of the Partnership's 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 the Partnership's equity interests in substantially all of its subsidiaries.

The Partnership may prepay all loans under the new credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The new credit facility will require 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 will not require any reduction of the lenders' commitments under the new credit facility.

Under the new credit facility, borrowings will 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. The Partnership will pay a per annum fee on all letters of credit issued under the new credit facility, and a commitment fee of 0.50% per annum on the unused availability under the new credit facility. The letter of credit fee and the applicable margins for its interest rate will vary quarterly based on the leverage ratio (as defined in the new 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 will be as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letter of Credit Fees
Greater than or equal to 5.00 to 1.00	3.25%	4.25%	4.25%
Greater than or equal to 4.50 to 1.00 and less than 5.00 to 1.00	3.00%	4.00%	4.00%
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	2.75%	3.75%	3.75%
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	2.50%	3.50%	3.50%
Less than 3.50 to 1.00	2.25%	3.25%	3.25%

Based on the forecasted leverage ratio for 2010, the Partnership expects the applicable margin for the interest rate and letter of credit fee to be at the higher end of these ranges. The new credit facility will not have a floor for the Base Rate or the Eurodollar Rate.

The new credit facility includes financial covenants that will be tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter (except for the interest coverage ratio, which builds to a four-quarter test during 2010).

The maximum permitted leverage ratio will be as follows:

- 5.75 to 1.00 for the fiscal quarters ending March 31, 2010 and June 30, 2010;
- 5.50 to 1.00 for the fiscal quarter ending September 30, 2010;
- 5.25 to 1.00 for the fiscal quarter ending December 31, 2010;
- 5.00 to 1.00 for the fiscal quarter ending March 31, 2011;
- 4.75 to 1.00 for the fiscal quarter ending June 30, 2011; and
- 4.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

The maximum permitted senior leverage ratio (as defined in the new 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), will be 2.50 to 1.00.

The minimum consolidated interest coverage ratio (as defined in the new 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) will be as follows:

- 1.50 to 1.00 for the fiscal quarter ending March 31, 2010;
- 1.75 to 1.00 for the fiscal quarters ending June 30, 2010 through December 31, 2010;
- 2.00 to 1.00 for the fiscal quarter ending March 31, 2011;
- 2.25 to 1.00 for the fiscal quarter ending June 30, 2011; and
- 2.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

In addition, the new credit facility will contain various covenants that, among other restrictions, will limit the Partnership's ability to:

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

The new credit facility will permit the Partnership to make quarterly distributions to unitholders so long as no default exists under the new credit facility.

Each of the following will be an event of default under the new 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 new credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- the Partnership 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 new credit facility).

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

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

The Partnership will be subject to interest rate risk on the new credit facility and may enter into interest rate swaps to reduce this risk.

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

Senior Secured Notes. The Partnership entered into a master shelf agreement with an institutional lender in 2003 that was amended in subsequent years to increase availability under the agreement, pursuant to which it issued the following senior secured notes (dollars in thousands):

Month Issued	Amount	Interest Rate
June 2003	$ 1,607	9.45%
July 2003	1,000	9.38%
June 2004	50,629	9.46%
November 2005	57,380	8.73%
March 2006	40,504	8.82%
July 2006	165,390	9.46%
Total Outstanding	316,510	
PIK Notes Payable (1)	9,524	
Balance as of December 31, 2009 (2)	$ 326,034	

(1) The senior secured notes began accruing additional interest of 1.25% per annum in February 2009 (the "PIK notes") in the form of an increase in the principal amounts unless our leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter.

(2) The senior secured notes were paid in full on February 10, 2010.

Series B Secured Note. On October 20, 2009, the Partnership acquired the Eunice natural gas liquids processing plant and fractionation facility which includes $18.1 million in series B secured note. This note bears an interest rate of 9.5%. Payments including interest of $12.2 million and $7.4 million are due in 2010 and 2011, respectively.

Senior Unsecured Notes. On February 10, 2010, the Partnership issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under the new credit facility discussed above, were used to repay in full amounts outstanding under the existing 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 existing credit facility. The notes are unsecured and unconditionally guaranteed on a senior basis by certain of our direct and indirect subsidiaries, including all of the Partnership's current subsidiaries other than Crosstex LIG, LLC and Crosstex Tuscaloosa, LLC, our Louisiana regulated entities, and Crosstex DC Gathering, J.V. Interest payments will be paid semi-annually in arrears starting on August 15, 2010.

The indenture governing the notes contains covenants that, among other things, will limit the Partnership's ability and the ability of certain of the Partnership's subsidiaries to:

- sell assets including equity interests in its subsidiaries;
- pay distributions on, redeem or repurchase its units or redeem or repurchase its subordinated debt;
- 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.

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

The Partnership may redeem up to 35% of the notes at any time prior to February 15, 2013 with the cash proceeds from equity offerings at a redemption price of 108.875% (of the principal amount plus accrued and unpaid interest to the redemption date), provided that:

- at least 65% of the aggregate principal amount of the senior notes remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 120 days of the date of the closing of the equity offering.

Prior to February 15, 2014, the Partnership may redeem the 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.

Each of the following will be 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; and
- the Partnership 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 unsecured 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 unsecured notes may accelerate the maturity of the senior unsecured notes and exercise other rights and remedies.

Credit Risk

Risks of nonpayment and nonperformance by the Partnership's customers are a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by its customers could adversely affect the results of operations and reduce the Partnership's ability to make distributions to its unitholders. Many of the Partnership's customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of the Partnership's customers' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in customers' liquidity and ability to make payments or perform on their obligations to the Partnership. Furthermore, some of the customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to the Partnership.

Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry has experienced an increase in labor and material costs during 2008 but 2009 remained relatively unchanged. These increases did not have a material impact on our results of operations for the periods presented. 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

The Partnership's operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe the Partnership is 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

In December 2008, Denbury initiated formal arbitration proceedings against Crosstex Processing, Crosstex Energy, Crosstex Gathering and Crosstex Marketing, all wholly-owned subsidiaries of the Partnership, asserting a claim for breach of contract under a gas processing agreement. Denbury alleged damages in the amount of $16.2 million, plus interest and attorneys' fees. Crosstex denied any liability and sought to have the action dismissed. A three-person arbitration panel conducted a hearing on the merits in December 2009. At the close of the evidence at the hearing, the panel granted judgment for Crosstex on one of Denbury's claims, and on February 16, 2010, the panel granted judgment for Denbury on its remaining claims in the amount of $3.0 million plus interest, attorneys' fees and costs. The panel will conduct additional proceedings to determine the amount of attorneys' fees and costs, if any, that should be awarded to Denbury. The Partnership estimates that the total award will be between $3.0 million and $4.0 million at the conclusion of these additional proceedings. The Partnership has accrued $3.7 million in other current liabilities for this award as of December 31, 2009 and reflected the related expense in purchased gas costs.

At times, the Partnership's gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain provided under state law. As a result, the Partnership (or its subsidiaries) is a 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 several 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, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed the Partnership approximately $6.2 million, including approximately $3.9 million for June 2008 sales and approximately $2.3 million for July 2008 sales. The Partnership believes the July sales of $2.3 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to Crosstex for an administrative claim in the amount of $2.3 million, but it remains subject to an objection by the lenders' agent. The Partnership evaluated these receivables for collectibility and provided a valuation allowance of $3.1 million and $0.8 million during the years ended December 31, 2008 and 2009, respectively.

Recent Accounting Pronouncements

As a result of the recent credit crisis, FASB ASC 820-10-35-15A was issued October 2008 and clarifies the application of FASB ASC 820 in a market that is not active and provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. FASB ASC 820-10-35-15A is effective upon issuance, for companies that have adopted FASB ASC 820. We have evaluated FASB ASC 820-10-35-15A and determined that this standard has no impact on our results of operations, cash flows or financial position for this reporting period.

FASB ASC 260-10-45-60 was issued June 2008 and requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB ASC 260. FASB ASC 260-10-45-60 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. We have adopted FASB ASC 260-10-45-60 effective January 1, 2009 and adjusted all prior periods to conform to the requirements.

FASB ASC 805 and FASB ASC 810-10-65-1 were issued December 2007. FASB ASC 805 requires most identifiable assets, liabilities, non-controlling interests and goodwill acquired in a business combination to be recorded at "full fair value." The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under FASB ASC 805 all business combinations will be accounted for by applying the acquisition method. FASB ASC 805 is effective for periods beginning on or after December 15, 2008. FASB ASC 810-10-65-1 requires non-controlling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. Additionally, gains and losses related to any subsidiary sales, if any, are to be reflected as equity transactions rather than reflected in net income as previously allowed. FASB ASC 810-10-65-1 was adopted effective January 1, 2009 and comparative period information has been recast to classify non-controlling interests in equity, and attribute net income and other comprehensive income to non-controlling interests.

FASB ASC 105 was released July 1, 2009 and intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of non-governmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. SFAS No. 162 has been superseded by SFAS No. 168, "*The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*" (the Codification) released July 1, 2009. The Codification became the exclusive authoritative reference for non-governmental U.S. GAAP for use in financial statements issued for interim and annual periods ending after September 15, 2009, except for Securities and Exchange Commission (SEC) rules and interpretive releases, which are also authoritative GAAP for SEC registrants. The change establishes non-governmental U.S. GAAP into the authoritative Codification and guidance that is non-authoritative. The contents of the Codification carry the same level of authority, eliminating the four-level GAAP hierarchy previously set forth in Statement 162. The Codification supersedes all existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the Codification has become non-authoritative. We have revised all GAAP references to reflect the Codification for the year ended December 31, 2009.

FASB ASC 815-10-65-1 was issued March 2008 and requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under FASB ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. FASB ASC 815-10-65-1 is effective for fiscal years beginning after November 15, 2008. FASB ASC 815-10-65-1 was adopted effective January 1, 2009. Required disclosures were added to Note 13.

In June 2009 FASB ASC 810-10-05-8 was issued. It requires reporting entities to evaluate former Qualifying Special Purpose Entities or QSPEs for consolidation, changes the approach to determining a variable interest entity's (VIE) primary beneficiary from a quantitative assessment to a qualitative assessment designed to identify a controlling financial interest, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. This statement requires additional year-end and interim disclosures for public and nonpublic companies that are similar to the disclosures required by FASB ASC 860-10-65-2. The statement is effective for fiscal years beginning after November 15, 2009 and for subsequent interim and annual reporting periods. We do not expect this statement to have a significant impact to our financial statements.

FASB ASC 855 was issued June 2009 and is effective for interim or annual financial periods ending after June 15, 2009 and addresses accounting and disclosure requirements related to subsequent events. The statement requires management to evaluate subsequent events through the date the financial statements are issued. Companies are required to disclose the date through which subsequent events have been evaluated. We have taken this statement into consideration in Note 19.

FASB ASC 825-10-65-1 requires publicly traded companies to disclose the fair value of financial instruments within the scope of FASB ASC 825 in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. FASB ASC 825-10-65-1 is effective for interim and annual periods ending after June 15, 2009. We have added the required footnote disclosure in interim financial statements.

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, 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 "may," "will," "should," "plan," "predict," "anticipate," "believe," "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. The Partnership's primary market risk is the risk related to changes in the prices of natural gas and NGLs. In addition, it is also exposed to the risk of changes in interest rates on floating rate debt.

Interest Rate Risk

The Partnership is exposed to interest rate risk on its variable rate bank credit facility. At December 31, 2009 and 2008, the bank credit facility had outstanding borrowings of $529.6 million and $784.0 million, respectively, which approximated fair value. The Partnership has managed a portion of its interest rate exposure on variable rate debt by utilizing interest rate swaps, which allow it to convert a portion of variable rate interest expense into fixed rate interest expense. As of December 31, 2009, the fair value of these interest rate swaps was reflected as a liability of $24.7 million ($17.9 million in net current liabilities and $6.8 million in long-term liabilities) on the Company's financial statements. We estimate that a 1% increase or decrease in the interest rate would increase or decrease the fair value of these interest rate swaps by approximately $12.7 million. Considering the amount outstanding on the Partnership's bank credit facility as of December 31, 2009, we estimate that a 1% increase or decrease in the interest rate would change its annual interest expense by approximately $5.3 million.

At December 31, 2009 and 2008, the Partnership had total fixed rate debt obligations of $344.1 million and $479.7 million, respectively, consisting of senior secured notes with a weighted average interest rate of 10.5% and a series B secured note with a fixed rate of 9.5%. The fair value of these fixed rate obligations was approximately $342.7 million and $374.4 million as of December 31, 2009 and 2008, respectively. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of the fixed rated debt (the senior secured notes) by $9.6 million based on the debt obligations as of December 31, 2009.

The debt obligations discussed above and the related interest rate swaps were liquidated during February 2010 in the completion of the Partnership's long-term recapitalization plan as discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — "Recent Developments and Business Strategy" under "Description of Indebtedness — Senior Unsecured Notes" and "Description of Indebtedness — New Credit Facility."

Commodity Price Risk

The Partnership is subject to significant risks due to fluctuations in commodity prices. Its exposure to these risks is primarily in the gas processing component of its business. The Partnership currently processes gas under three main types of contractual arrangements:

1. *Processing margin contracts:* Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant, and makes 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") at the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR. The Partnership's 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, the Partnership mitigates its risk of processing natural gas when its margins are negative under its current processing margin contracts primarily through its ability to bypass processing when it is not profitable for the Partnership, 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, the Partnership receives 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, its margins from these contracts are greater during periods of high liquids prices. The Partnership's 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 the Partnership has no commodity price exposure, and is paid a fixed fee per unit of volume that is processed.

The gross margin presentation in the table below is calculated net of results from discontinued operations. Gas processing margins by contract types and gathering and transportation margins as a percent of total gross margin for the comparative year-to-date periods are as follows:

	Years Ended December 31,		
	2009	2008	2007
Gathering and transportation margin	65.8%	57.6%	45.1%
Gas processing margins:			
Processing margin	8.9%	15.4%	16.8%
Percent of liquids	13.2%	17.9%	28.1%
Fee based	12.1%	9.1%	10.0%
Total gas processing	34.2%	42.4%	54.9%
Total	100.0%	100.0%	100.0%

The Partnership has hedges in place at December 31, 2009 covering a portion of the liquids volumes it expects to receive under percent of liquids (POL) contracts as 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 2010-December 2010	Ethane	63 (MBbls)	Index	$0.5981/gal	$ (280)
January 2010-December 2010	Propane	109 (MBbls)	Index	$0.9584/gal	(1,236)
January 2010-December 2010	Normal Butane	40 (MBbls)	Index	$1.2580/gal	(420)
January 2010-December 2010	Natural Gasoline	21 (MBbls)	Index	$1.4815/gal	(231)
					$ (2,167)

* weighted average

The Partnership has hedged its exposure to declines in prices for a portion of the NGL volumes produced for its account. The NGL volumes hedged, as set forth above, focus on POL contracts. The Partnership hedges POL exposure based on volumes considered 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. The Partnership hedged 63.7% of its hedgeable volumes at risk through the end of 2010 (24.5% of total volumes at risk).

The Partnership also has hedges in place at December 31, 2009 covering the fractionation spread risk related to its 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 2010-December 2010	Ethane	193 (MBbls)	Index	$0.5009/gal*	$ (1,467)
January 2010-December 2010	Propane	85 (MBbls)	Index	$0.9226/gal*	(1,063)
January 2010-December 2010	Normal Butane	57 (MBbls)	Index	$1.2007/gal*	(712)
January 2010-December 2010	Natural Gasoline	56 (MBbls)	Index	$1.5305/gal*	(476)
January 2010-December 2010	Natural Gas	4,695 (MMbtu/d)	$5.7096/MMBtu*	Index	92
					$ (3,626)

* weighted average

In relation to its fractionation spread risk, as set forth above, the Partnership has hedged 59.2% of its hedgeable liquids volumes at risk through the end of 2010 (32.7% of total liquids volumes at risk) and 62.6% of the related hedgeable PTR volumes through the end of 2010 (32.7% of total PTR volumes).

The Partnership is also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of its gathering and transport services. Approximately 8.0% of the natural gas the Partnership markets 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, resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices.

Another price risk the Partnership faces is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. The Partnership enters 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 it with short or long positions that must be covered. The Partnership uses financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The Partnership's primary commodity risk management objective is to reduce volatility in its cash flows. The Partnership maintains a risk management committee, including members of senior management, which oversees all hedging activity. The Partnership enters 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 its risk management committee.

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

As of December 31, 2009, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $2.9 million. The aggregate effect of a hypothetical 10% increase in gas and NGLs prices would result in an increase of approximately $2.3 million in the net fair value liability of these contracts as of December 31, 2009.

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-42 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 our management, including our Chief Executive Officer and Chief Financial Officer, 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, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2009 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

(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, 2009 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***

The following table shows information about our executive officers. Executive officers serve until their successors are elected or appointed.

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis(1)	48	President, Chief Executive Officer and Director
William W. Davis(1)	56	Executive Vice President and Chief Financial Officer
Joe A. Davis(1)	49	Executive Vice President, General Counsel and Secretary
Michael J. Garberding	41	Senior Vice President—Finance
Stan Golemon	46	Senior Vice President of Engineering and Operations

(1) Not related.

Barry E. Davis, President, Chief Executive Officer and Director, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of the Partnership's predecessor. Mr. Davis has served as director since the Partnership's initial public offering in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis also serves as a director of Crosstex Energy GP, LLC, the general partner of the general partner of the Partnership. Mr. Davis holds a B.B.A. in Finance from Texas Christian University. Mr. Davis also serves as the Chairman of the Board for Crosstex Energy, Inc.

William W. Davis, Executive Vice President and Chief Financial Officer, joined the Partnership's predecessor in September 2001, and has over 30 years of finance and accounting experience. Mr. Davis has served as Chief Financial Officer since joining the Partnership's predecessor. Prior to joining the Partnership's predecessor, Mr. Davis held various positions with Sunshine Mining and Refining Company from 1983 to September 2001, including Vice President-Financial Analysis from 1983 to 1986, Senior Vice President and Chief Accounting Officer from 1986 to 1991 and 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.

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 bachelor of science from the University of Texas in Dallas.

Michael J. Garberding, Senior Vice President — Finance joined Crosstex Energy GP, LLC in February 2008. Mr. Garberding has 20 years experience in finance and accounting. Prior to joining Crosstex, Mr. Garberding was assistant treasurer at TXU Corporation. 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 of Engineering and Operations, joined Crosstex Energy GP, LLC in May of 2008. Mr. Golemon has 25 years of experience in engineering, operations, and commercial development in the midstream and E&P industries. Immediately prior to joining Crosstex, Mr. Golemon held various midstream engineering, commercial, and management positions with Union Pacific Resources and its successor company Anadarko Petroleum Corporation. 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, onshore facilities, 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.

Code of Ethics

We adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers, and directors, with regard to company-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. The Code of Ethics also incorporates our expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission 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 grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our executive officers and directors, we will disclose the nature of such amendment or waiver on our web site.

Other

The sections entitled “Proposal One: Election of Directors”, “Additional Information Regarding the Board of Directors”, “Section 16(a) Beneficial Ownership Reporting Compliance”, and “Stockholder Proposals and Other Matters” that will appear in our proxy statement for the 2010 annual meeting of stockholders, which we expect to file with the Securities and Exchange Commission within 120 days after December 31, 2009 (the “2010 Proxy Statement”), will set forth certain information with respect to our directors and with respect to reporting under Section 16(a) of the Securities Exchange Act of 1934, and are incorporated herein by reference.

Item 11. ***Executive Compensation***

The section entitled “Executive Compensation” that will appear in the 2010 Proxy Statement will set forth certain information with respect to the compensation of our management, and is incorporated herein by reference.

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

The sections entitled “Equity Compensation Plans” and “Security Ownership of Certain Beneficial Owners and Management” that appears in the 2010 Proxy Statement will set forth certain information with respect to securities authorized for issuance under equity compensation plans and the ownership of voting securities and equity securities of us, and are incorporated herein by reference.

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

The sections entitled “Certain Relationships and Related Party Transactions” and “Additional Information Regarding the Board of Directors” that will appear in the 2010 Proxy Statement will set forth certain information with respect to certain relationships and related party transactions, and are incorporated herein by reference.

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

The section entitled “Fees Paid to Independent Public Accounting Firm” that will appear in the 2010 Proxy Statement will set forth certain information with respect to accounting fees and services, and is incorporated herein by reference.

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) See Schedule I — Parent Company Statements on page F-39 and Schedule II — Valuation and Qualifying Accounts on Page F-42.

(3) 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**	—	Partnership Interest Purchase and Sale Agreement, dated as of June 9, 2009, among Crosstex Energy Services, L.P., Crosstex Energy Services GP, LLC, Crosstex CCNG Gathering, Ltd., Crosstex CCNG Transmission Ltd., Crosstex Gulf Coast Transmission Ltd., Crosstex Mississippi Pipeline, L.P., Crosstex Mississippi Gathering, L.P., Crosstex Mississippi Industrial Gas Sales, L.P., Crosstex Alabama Gathering System, L.P., Crosstex Midstream Services, L.P., Javelina Marketing Company Ltd., Javelina NGL Pipeline Ltd. and Southcross Energy LLC (incorporated by reference to Exhibit 2.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 9, 2009, filed with the Commission on June 11, 2009, file No. 000-50067).
2.2**	—	Partnership Interest Purchase and Sale Agreement, dated as of August 28, 2009, among Crosstex Energy Services, L.P., Crosstex Energy Services GP, LLC, Crosstex Treating Services, L.P. and KM Treating GP LLC (incorporated by reference to Exhibit 2.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated August 28, 2009, filed with the Commission on September 3, 2009, file No. 000-50067).
3.1	—	Amended and Restated Certificate of Incorporation of Crosstex Energy, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006, file No. 000-50536).
3.2	—	Third Amended and Restated Bylaws of Crosstex Energy, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 22, 2006, filed with the Commission on March 28, 2006, file No. 000-50536).
3.3	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.4	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007, file No. 000-50067).
3.5	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007, file No. 000-50067).
3.6	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008, file No. 000-50067).
3.7	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
3.8	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).

Number		Description
3.9	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.10	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.11	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.12	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.13	—	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 Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.14	—	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 Crosstex Energy, L.P.'s 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 Certificate representing shares of common stock (incorporated by reference from Exhibit 4.1 to our Registration Statement on Form S-1, file No. 333-110095).
4.2	—	Registration Rights Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007, file No. 000-50067).
4.3	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
4.4	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
4.5	—	Registration Rights Agreement, dated as of February 10, 2010, 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 4.2 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, 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 our 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 Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, file No. 000-50067).

Number		Description
10.3†	—	Crosstex Energy, Inc. 2009 Long-Term Incentive Plan, effective 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. 000-50536).
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 Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.5†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.6†	—	Form of Severance Agreement (incorporated by reference to Exhibit 10.6 to Crosstex Energy, L.P.'s Annual Report on Form 10K for the year ended December 31, 2009, file No. 000-50067).
10.7†	—	Form of Performance Unit Agreement (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007, file No. 000-50067).
10.8†	—	Form of Performance Share 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. 000-50536).
10.9†*	—	Form of Restricted Stock Agreement.
10.10†	—	Form of Restricted Unit Agreement (incorporated by reference to Exhibit 10.9 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2009, file No. 000-50067).
10.11	—	Senior Subordinated Series D Unit Purchase Agreement, dated as of March 23, 2007, 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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007, file No. 000-50067).
10.12	—	Common Unit Purchase Agreement, dated as of April 8, 2008, by and among Crosstex Energy, L.P. and each of the Purchasers set forth Schedule A thereto (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated April 9, 2008, file No. 000-50067).
10.13	—	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.14	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
10.15	—	Purchase Agreement, dated as of February 3, 2010, 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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated February 3, 2010, filed with the Commission on February 5, 2010, file No. 000-50067).
10.16	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).

Number		Description
10.17	—	Agreement Regarding 2003 Registration Statement and Waiver and Termination of Stockholders' Agreement, dated October 27, 2003 (incorporated by reference from Exhibit 10.4 to our Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.18	—	Registration Rights Agreement, dated December 31, 2003 (incorporated by reference from Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
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.

* Filed herewith.

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

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

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 26th day of February 2010.

CROSSTEX ENERGY, INC.

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 by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 26, 2010
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 26, 2010
/s/ JAMES C. CRAIN James C. Crain	Director	February 26, 2010
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Lead Director	February 26, 2010
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	February 26, 2010
/s/ CECIL E. MARTIN Cecil E. Martin	Director	February 26, 2010
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	February 26, 2010
/s/ WILLIAM W. DAVIS William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2010

INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Crosstex Energy, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting (Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended) and for the assessment of the effectiveness of internal control over financial reporting for Crosstex Energy, Inc. (the "Company"). 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, Inc.'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 Company'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 Company's transactions and dispositions of the Company'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 Company's management and directors; 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 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 Company's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, 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 Company'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, 2009, the Company'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 Company's consolidated financial statements included in this report, has issued an attestation report on the Company's internal control over financial reporting, a copy of which appears on page F-3 of this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and the Stockholders of Crosstex Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedules. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules 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, Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, 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 February 26, 2010, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Dallas, Texas
February 26, 2010

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Crosstex Energy, Inc.:

We have audited Crosstex Energy, Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company'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 Company'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 Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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 Company as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 26, 2010, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Dallas, Texas
February 26, 2010

CROSSTEX ENERGY, INC.

Consolidated Balance Sheets

	December 31, 2009	December 31, 2008
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,703	$ 13,959
Accounts receivable:		
Trade, net of allowance for bad debts of $410 and $3,655, respectively	27,434	49,185
Accrued revenues	180,221	292,668
Imbalances	6,020	3,893
Other	1,075	7,618
Fair value of derivative assets	9,112	27,166
Natural gas and natural gas liquids, prepaid expenses and other	14,692	9,658
Total current assets	249,257	404,147
Property and equipment:		
Transmission assets	382,965	474,771
Gathering systems	605,981	614,572
Gas plants	457,139	577,250
Other property and equipment	80,476	72,106
Construction in process	12,693	86,462
Total property and equipment	1,539,254	1,825,161
Accumulated depreciation	(259,057)	(296,671)
Total property and equipment, net	1,280,197	1,528,490
Fair value of derivative assets	5,665	4,628
Intangible assets, net of accumulated amortization of $115,813 and $89,231, respectively	534,897	578,096
Goodwill	—	19,673
Other assets, net	10,217	11,709
Total assets	$ 2,080,233	$ 2,546,743
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Drafts payable	$ 5,214	$ 21,514
Accounts payable	17,978	23,879
Accrued gas purchases	150,816	270,229
Accrued imbalances payable	5,702	7,100
Fair value of derivative liabilities	30,337	28,506
Current portion of long-term debt	28,602	9,412
Other current liabilities	52,399	63,938
Total current liabilities	291,048	424,578
Long-term debt	845,100	1,254,294
Other long-term liabilities	20,797	24,708
Deferred tax liability	95,272	81,998
Fair value of derivative liabilities	12,106	22,775
Commitments and contingencies	—	—
Stockholders' equity:		
Common stock (150,000,000 shares authorized, $.01 par value, 46,524,177 and 46,341,621 issued and outstanding in 2009 and 2008, respectively)	464	464
Additional paid-in capital	271,669	268,988
Accumulated deficit	(43,279)	(54,693)
Interest of non-controlling partners in the Partnership	587,624	522,961
Accumulated other comprehensive income (loss)	(568)	670
Total stockholders' equity	815,910	738,390
Total liabilities and stockholders' equity	$ 2,080,233	$ 2,546,743

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Operations

	Years Ended December 31, 2009	2008	2007
	(In thousands, except per share data)		
Revenues:			
Midstream	$ 1,453,346	$ 3,072,646	$ 2,380,224
Gas and NGL marketing activities	5,744	3,365	4,105
Total revenues	1,459,090	3,076,011	2,384,329
Operating costs and expenses:			
Purchased gas	1,147,868	2,768,225	2,124,503
Operating expenses	110,394	125,762	91,236
General and administrative	62,491	72,377	62,270
Gain on derivatives	(2,994)	(8,619)	(4,147)
Gain on sale of property	(666)	(947)	(1,024)
Impairments	2,894	30,177	—
Depreciation and amortization	119,162	107,652	83,361
Total operating costs and expenses	1,439,149	3,094,627	2,356,199
Operating income (loss)	19,941	(18,616)	28,130
Other income (expense):			
Interest expense, net	(95,078)	(74,861)	(47,649)
Loss on extinguishment of debt	(4,669)	—	—
Other income	1,449	27,898	538
Total other income (expense)	(98,298)	(46,963)	(47,111)
Loss from continuing operations before income taxes and gain on issuance of Partnership units	(78,357)	(65,579)	(18,981)
Income tax benefit (provision) from continuing operations	6,020	1,375	(6,319)
Gain on issuance of Partnership units	—	14,748	7,461
Income (loss) from continuing operations	(72,337)	(49,456)	(17,839)
Discontinued operations:			
Income (loss) from discontinued operations-net of tax of $225, $(3,541) and $(4,527), respectively	(1,519)	21,466	26,817
Gain from sale of discontinued operations-net of tax of $(23,735) and $(7,053), respectively	159,961	42,753	—
Discontinued operations-net of tax	158,442	64,219	26,817
Net income	86,105	14,763	8,978
Less: Interest of non-controlling partners in the Partnership's net income (loss):			
Interest of non-controlling partners in the Partnership's continuing operations	(48,069)	(55,704)	(22,331)
Interest of non-controlling partners in the Partnership's discontinued operations	(1,137)	15,454	19,133
Interest of non-controlling partners in the Partnership's gain on sale of discontinued operations	119,669	30,780	—
Total interest of non-controlling partners in the Partnership's net income (loss)	70,463	(9,470)	(3,198)
Net income attributable to Crosstex Energy, Inc.	$ 15,642	$ 24,233	$ 12,176
Net income from continuing operations per common share:			
Basic	$ (0.52)	$ 0.13	$ 0.10
Diluted	$ (0.52)	$ 0.13	$ 0.09
Net income from discontinued operations per common share:			
Basic	$ 0.85	$ 0.38	$ 0.16
Diluted	$ 0.85	$ 0.38	$ 0.16
Net income per common share:			
Basic	$ 0.33	$ 0.52	$ 0.26
Diluted	$ 0.33	$ 0.51	$ 0.26
Weighted-average shares outstanding:			
Basic	46,476	46,298	45,988
Diluted	46,535	46,589	46,607
Dividends per share:			
Common	$ 0.09	$ 1.32	$ 0.91
Amounts attributable to Crosstex Energy, Inc. common shareholders:			
Income (loss) from continuing operations, net of tax and non-controlling interest	$ (24,267)	$ 6,249	$ 4,492
Income (loss) from discontinued operations, net of tax and non-controlling interest	(383)	6,011	7,684
Gain on sale of discontinued operations, net of tax and non-controlling interest	40,292	11,973	—
Net income attributable to Crosstex Energy, Inc.	$ 15,642	$ 24,233	$ 12,176

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Changes in Stockholders' Equity
Years Ended December 31, 2009, 2008 and 2007

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total Stockholders' Equity
Balance, December 31, 2006	45,941	$ 463	$ 263,264	$ 13,535	$ 2,151	$ 391,103	$ 670,516
Conversion of restricted stock to common, net of shares withheld for taxes	63	—	(919)	—	—		(919)
Proceeds from exercise of stock options	15	—	98	—	—		98
Stock-based compensation	—	—	5,416	—	—	6,843	12,259
Common dividends	—	—	—	(42,589)	—	—	(42,589)
Net income	—	—	—	12,176	—	(3,198)	8,978
Non-controlling partners' share of other comprehensive income in Partnership	—	—	—	—	281		281
Hedging gains or losses reclassified to earnings	—	—	—	—	(963)	(2,179)	(3,142)
Adjustment in fair value of derivatives	—	—	—	—	(6,547)	(15,553)	(22,100)
Contributions from non-controlling interest						150,978	150,978
Distribution to non-controlling interest	—	—	—	—	—	(38,960)	(38,960)
Balance, December 31, 2007	46,019	463	267,859	(16,878)	(5,078)	489,034	735,400
Conversion of restricted stock to common, net of shares withheld for taxes	285	—	(3,815)	—	—		(3,815)
Proceeds from exercise of stock options	38	1	243	—	—		244
Stock-based compensation	—	—	4,701	—	—	6,578	11,279
Common dividends	—	—	—	(62,048)	—	—	(62,048)
Net income	—	—	—	24,233	—	(9,470)	14,763
Non-controlling partners' share of other comprehensive income in Partnership	—	—	—	—	431		431
Hedging gains or losses reclassified to earnings	—	—	—	—	4,689	13,402	18,091
Adjustment in fair value of derivatives	—	—	—	—	628	2,747	3,375
Contributions from non-controlling interest						83,820	83,820
Distribution to non-controlling interest	—	—	—	—	—	(63,150)	(63,150)
Balance, December 31, 2008	46,342	464	268,988	(54,693)	670	522,961	738,390
Offering costs	—	—	(42)	—	—	—	(42)
Conversion of restricted stock to common, net of shares withheld for taxes	182	—	(354)	—	—		(354)
Stock-based compensation	—	—	3,077	—	—	5,778	8,855
Common dividends	—	—	—	(4,228)	—	—	(4,228)
Net income	—	—	—	15,642	—	70,463	86,105
Hedging gains or losses reclassified to earnings	—	—	—	—	(550)	(1,537)	(2,087)
Adjustment in fair value of derivatives	—	—	—	—	(688)	(2,276)	(2,964)
Distribution to non-controlling interest	—	—	—	—	—	(7,765)	(7,765)
Balance, December 31, 2009	46,524	$ 464	$ 271,669	$ (43,279)	$ (568)	$ 587,624	$ 815,910

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Comprehensive Income

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Net income	$ 86,105	$ 14,763	$ 8,978
Non-controlling partners' share of other comprehensive income in the Partnership, net of taxes of $0, $254, and $103, respectively	—	431	281
Hedging gains or losses reclassified to earnings, net of taxes of $(324), $2,765, and $(564), respectively	(550)	4,689	(963)
Adjustment in fair value of derivatives, net of taxes of $(406), $372, and $(3,783) respectively	(688)	628	(6,547)
Comprehensive income	84,867	20,511	1,749
Comprehensive income (loss) attributable to non-controlling interest	70,463	(9,470)	(3,198)
Comprehensive income attributable to Crosstex Energy, Inc.	$ 14,404	$ 29,981	$ 4,947

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 86,105	$ 14,763	$ 8,978
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	129,812	133,030	108,926
Non-cash stock-based compensation	8,855	11,279	12,259
Gain on sale of property	(184,412)	(51,325)	(1,667)
Impairment	2,894	31,240	—
Deferred tax expense	15,229	7,022	10,338
Gain on issuance of units of the Partnership	—	(14,748)	(7,461)
Non-cash derivatives loss	2,184	23,510	2,418
Non-cash loss on debt extinguishment	4,669	—	—
Interest paid-in-kind	10,134	—	—
Amortization of debt issue costs	11,812	2,854	2,639
Changes in assets and liabilities net of acquisition effects:			
Accounts receivable, accrued revenue, and other	127,981	156,280	(121,285)
Natural gas and natural gas liquids, prepaid expenses and other	(5,275)	5,199	(5,498)
Accounts payable, accrued gas purchases, and other accrued liabilities	(131,126)	(148,950)	102,096
Fair value of derivatives	(12)	—	835
Net cash provided by operating activities	78,850	170,154	112,578
Cash flows from investing activities:			
Additions to property and equipment	(101,370)	(275,548)	(414,452)
Insurance recoveries on property and equipment	12,458	—	—
Acquisitions and asset purchases	(35,142)	—	—
Proceeds from sale of property	503,928	88,780	3,070
Net cash provided by (used in) investing activities	379,874	(186,768)	(411,382)
Cash flows from financing activities:			
Proceeds from borrowings	632,807	1,743,580	1,189,500
Payments on borrowings	(1,050,389)	(1,702,992)	(953,512)
Proceeds from capital lease obligations	1,695	28,010	3,553
Payments on capital lease obligations	(2,414)	(4,101)	—
Increase (decrease) in drafts payable	(16,300)	(7,417)	(19,017)
Debt refinancing costs	(15,031)	(4,903)	(892)
Distributions to non-controlling partners in the Partnership	(7,601)	(63,149)	(38,960)
Common dividends paid	(4,228)	(62,048)	(42,589)
Proceeds from exercise of common stock option	—	244	98
Conversion of restricted units, net of units withheld for taxes	(232)	(1,536)	(329)
Conversion of restricted stock, net of shares withheld for taxes	(354)	(3,815)	(919)
Net proceeds from issuance of units of the Partnership	—	99,888	157,491
Proceeds from exercise of Partnership unit options	67	850	1,598
Contributions from non-controlling partners in the Partnership	—	109	—
Net cash provided by (used in) financing activities	(461,980)	22,720	296,022
Net increase (decrease) in cash and cash equivalents	(3,256)	6,106	(2,782)
Cash and cash equivalents, beginning of period	13,959	7,853	10,635
Cash and cash equivalents, end of period	$ 10,703	$ 13,959	$ 7,853
Cash paid for interest	$ 85,466	$ 76,291	$ 79,648
Cash paid (refunded) for income taxes	$ 926	$ 1,821	$ (45)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements
December 31, 2009 and 2008

(1) Organization and Summary of Significant Agreements:

(a) Description of Business

CEI, a Delaware corporation formed on April 28, 2000, is engaged, through its subsidiaries, in the gathering, transmission, processing and marketing of natural gas and natural gas liquids (NGLs). The Company connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, processes natural gas for the removal of NGLs, transports natural gas and NGLs and ultimately provides natural gas and NGLs to a variety of markets. In addition, the Company purchases natural gas and NGLs from producers not connected to its gathering systems for resale and markets natural gas and NGLs on behalf of producers for a fee.

(b) Organization

On July 12, 2002, the Company formed Crosstex Energy, L.P. (herein referred to as the Partnership or CELP), a Delaware limited partnership. Crosstex Energy GP, L.P., a wholly owned subsidiary of the Company, is the general partner of the Partnership. The Company owns 16,414,830 common units in the Partnership through its wholly-owned subsidiaries on December 31, 2009 which represented 33.0% of the limited partner interests in the Partnership.

After the Partnership's January 2010 issuance of Series A Convertible Preferred Units as discussed in Note 19, the common units owned by CEI represent 25.0% of the limited partner interests in the Partnership.

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities and results of operations of the Company and its majority owned subsidiaries, including the Partnership. The Company proportionately consolidates the Partnership's undivided 59.27% interest in a gas processing plant. In accordance with FASB ASC 810-10-05-8 the Company consolidates its joint venture interest in Crosstex DC Gathering, J.V. (CDC) as discussed more fully in Note 6. The consolidated operations are hereafter referred to collectively as the Company. All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for the prior years to conform to the current presentation.

(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 Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(b) Cash and Cash Equivalents

The Company 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

Inventories of products consist of natural gas and natural gas liquids. The Company 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, industrial supply pipelines, NGL pipelines, natural gas processing plants and NGL fractionation plants. Gas required to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Other property and equipment is primarily comprised of idle gas plants, 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. Interests costs totaling $1.1 million, $2.7 million and $4.8 million were capitalized for the years ended December 31, 2009, 2008 and 2007, 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 $82.5 million, $76.3 million and $57.0 million was recorded for the years ended December 31, 2009, 2008 and 2007, respectively. During the fourth quarter of 2009, the Partnership reviewed the estimated useful lives and salvage values of its assets in light of the capital improvements made to its assets over the past years. As a result of this review, the Partnership extended the depreciable lives on some of its transmission assets, gathering systems and gas processing plants by five years. This change in estimated depreciable lives is being applied prospectively and will result in lower depreciation expense of approximately $9.3 million annually in future periods.

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 Company compares the net book value of the asset to the undiscounted expected future net cash flows. If an impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. The Company's 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 to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas 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.

The Company recorded impairments to long-lived assets of $2.9 and $24.6 million during the years ending December 31, 2009 and 2008 respectively. See Note 4(c) for further details on the long-lived assets impaired.

(e) Goodwill and Intangibles

Goodwill created in the formation of the Partnership of $5.7 million net book value associated with the Midstream assets was impaired during the year ending December 31, 2008. The goodwill related to the acquisition of Treating assets and was eliminated in the disposition of all Treating assets during 2009.

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 15 years. The intangible assets associated with non-dedicated acreage attributable to pipeline, gathering and processing systems are being amortized using the units of throughput method of amortization. The weighted average amortization period for intangible assets is 18.0 years. Amortization expense for intangibles was approximately $36.6 million, $31.4 million and $26.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

2010	$ 40,646
2011	42,642
2012	45,303
2013	46,731
2014	46,701
Thereafter	312,874
Total	$ 534,897

(f) Other Assets

Unamortized debt issuance costs totaling $10.2 million, and $11.7 million as of December 31, 2009 and 2008, respectively, are included in other assets, net. Debt issuance costs are amortized into interest expense over the term of the related debt. Debt issuance costs are amortized into interest expense using the effective-interest method over the term of the debt for the senior secured notes. Debt issuance costs are amortized using the straight-line method over the term of the debt for the bank credit facility because borrowings under the bank credit facility cannot be forecasted for an effective-interest computation.

(g) 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 Company had imbalance payables of $5.7 million, and $7.1 million at December 31, 2009 and 2008, respectively, which approximates the fair value for these imbalances. The Company had imbalance receivables of $6.0 million and $3.9 million at December 31, 2009 and 2008, which are carried at the lower of cost or market value.

(h) Asset Retirement Obligations

FASB ASC 410-20-25-16 was issued 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 Company did not provide any asset retirement obligations as of December 31, 2008 or 2007 because it does not have sufficient information as set forth in FASB ASC 410-20-25-16 to reasonably estimate such obligations and the Company has no current intention of discontinuing use of any significant assets.

(i) Revenue Recognition

The Company recognizes revenue for sales or services at the time the natural gas or NGLs are delivered or at the time the service is performed. The Company 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. Purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the statements of operations in accordance with FASB ASC 605-45-45-1. Except for fee based arrangements and energy trading activities related to "off-system" gas marketing operations discussed in Note 2(k), the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, and schedules the transportation and assumes credit risk.

The Company accounts for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

(j) Derivatives

The Partnership uses derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. FASB ASC 815 requires that all derivatives be recorded on the balance sheet at fair value. It generally determines the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet in fair value of derivative assets or liabilities.

Realized and unrealized gains and losses on commodity related derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, are recorded as gain or loss on derivatives in the consolidated statement of operations. 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.

(k) Gas and NGL Marketing Activities

The Company conducts "off-system" gas marketing operations as a service to producers on systems that the Company does not own. The Company refers to these activities as part of its Gas and NGL marketing activities. In some cases, the Company earns an agency fee from the producer for arranging the marketing of the producer's natural gas or NGLs. In other cases, the Company purchases the natural gas or NGLs from the producer and enters into a sales contract with another party to sell the natural gas or NGLs. The revenue and cost of sales for Gas and NGL marketing activities are shown net in the consolidated statements of operations.

The Company manages its price risk related to future physical purchase or sale commitments for its Gas and NGL marketing activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance the Company's future commitments and significantly reduce its risk to the movement in natural gas and NGL prices. However, the Company is subject to counterparty risk for both the physical and financial contracts. The Company's Gas and NGL marketing contracts qualify as derivatives, and accordingly, the Company continues to use mark-to-market accounting for both physical and financial contracts of its Gas and NGL marketing activities. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Company's Gas and NGL marketing activities are recognized in earnings as gain or loss on derivatives immediately.

Net margins earned on settled contracts from the Company's Gas and NGL marketing activities included in Gas and NGL marketing activities in the consolidated statement of operations were $5.7 million, $3.4 million, and $4.1 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Gas and NGL marketing contract volumes that were physically settled were as follows (in MMBtus):

	Years Ended December 31,		
	2009	2008	2007
Volumes purchased and sold	27,375,000	31,003,000	34,432,000

(l) Comprehensive Income (Loss)

Comprehensive income includes net income and other comprehensive income, which includes, unrealized gains and losses on derivative financial instruments.

Pursuant to FASB ASC 815, the Company records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges, net of income tax and minority interest, 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 Company to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited since the Company's customers represent a broad and diverse group of energy marketers and end users. In addition, the Company continually monitors and reviews credit exposure to its marketing counterparties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. The Company records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Company had a reserve for uncollectible receivables as of December 31, 2009, 2008 and 2007 of $0.4 million, $3.7 million, and $1.0 million, respectively. The increase in reserve in 2008 primarily relates to SemStream, L. P. The decrease in the reserve during 2009 primarily relates to the write-off of the Semstream reserve and related receivable. See Note 16(e) for a discussion of the bankruptcy of SemStream, L. P. and related subsidiaries.

During 2009, 2008 and 2007, Dow Hydrocarbons accounted for 12.2%, 11.0%, and 11.8%, respectively, of the consolidated revenue of the Company including discontinued operations. As the Company continues to grow and expand, this relationship between individual customer sales and consolidated total sales is expected to continue to change. While this customer represents a significant percentage of revenues, the loss of this customer would not have a material adverse impact on the Company's results of operations.

(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, 2009, 2008 and 2007, such expenditures were not significant.

(p) Option Plans

The Company 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. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Cost of share-based compensation charged to general and administrative expense	$ 7,075	$ 9,364	$ 10,417
Cost of share-based compensation charged to operating expense	1,667	1,879	1,842
Total amount charged to income before cumulative effect of accounting change	$ 8,742	$ 11,243	$ 12,259
Interest of non-controlling partners in share-based compensation	$ 3,729	$ 4,014	$ 4,214
Amount of related income tax benefit recognized in income	$ 1,871	$ 2,685	$ 2,982

The fair value of each option is estimated on the date of grant using the Black Scholes option-pricing model as disclosed in Note 11 — Employee Incentive Plans.

(q) Sales of Securities by Subsidiaries

Prior to January 1, 2009, the Company recognized gains and losses in its consolidated statements of operations resulting from subsidiary sales of additional equity interests, including exercises of unit options and issuance of CELP limited partnership units, to unrelated parties as discussed in Note 3(a). Pursuant to new accounting guidance, effective January 1, 2009, gains and losses related to any subsidiary sales, if any, are reflected as equity transactions in the Company's consolidated statements of changes in stockholders' equity.

(r) Financial Statement Recast for Discontinued Operations and Letter of Credit Fees

The consolidated statements of operations and related earnings per unit for the years ended December 31, 2008 and 2007 have been recast to segregate income related to assets sold in 2009 to discontinued operations and reclassify letter of credit fees from purchased gas expense to interest expense. During 2008 and 2009 the Partnership disposed of assets and the financial activities of these assets have now been included in discontinued operations in the recast consolidated statements of operations for all periods presented. See Note 4(a). Additionally, letter of credit fees of $1.5 million and $1.3 million for the years ended December 31, 2008 and 2007, respectively, were reclassified from purchased gas expense to interest expense in the consolidated statements of operations.

(s) Recent Accounting Pronouncements

As a result of the recent credit crisis, FASB ASC 820-10-35-15A was issued in October 2008 and clarifies the application of FASB ASC 820 in a market that is not active and provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. FASB ASC 820-10-35-15A is effective upon issuance, for companies that have adopted FASB ASC 820. The Company has evaluated FASB ASC 820-10-35-15A and determined that this standard has no impact on its results of operations, cash flows or financial position for this reporting period.

FASB ASC 260-10-45-60 was issued June 2008 and requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB ASC 260. FASB ASC 260-10-45-60 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. The Company adopted FASB ASC 260-10-45-60 effective January 1, 2009 and adjusted all prior periods to conform to the requirements.

FASB ASC 805 and FASB ASC 810-10-65-1 were issued December 2007. FASB ASC 805 requires most identifiable assets, liabilities, non-controlling interests and goodwill acquired in a business combination to be recorded at "full fair value." The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under FASB ASC 805 all business combinations will be accounted for by applying the acquisition method. FASB ASC 805 is effective for periods beginning on or after December 15, 2008. FASB ASC 810-10-65-1 requires non-controlling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. Additionally, gains and losses related to any subsidiary sales, if any, are to be reflected as equity transactions rather than reflected in net income as previously allowed. FASB ASC 810-10-65-1 was adopted effective January 1, 2009 and comparative period information has been recast to classify non-controlling interests in equity, and attribute net income and other comprehensive income to non-controlling interests.

FASB ASC 105 was released July 1, 2009 and intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of non-governmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. SFAS No. 162 has been superseded by SFAS No. 168, "*The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles"* (the Codification) released July 1, 2009. The Codification became the exclusive authoritative reference for non-governmental U.S. GAAP for use in financial statements issued for interim and annual periods ending after September 15, 2009, except for Securities and Exchange Commission (SEC) rules and interpretive releases, which are also authoritative GAAP for SEC registrants. The change establishes non-governmental U.S. GAAP into the authoritative Codification and guidance that is non-authoritative. The contents of the Codification carry the same level of authority, eliminating the four-level GAAP hierarchy previously set forth in Statement 162. The Codification supersedes all existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the Codification has become non-authoritative. The Company has revised all GAAP references to reflect the Codification for the year ended December 31, 2009.

FASB ASC 815-10-65-1 was issued March 2008 and requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under FASB ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. FASB ASC 815-10-65-1 is effective for fiscal years beginning after November 15, 2008. FASB ASC 815-10-65-1 was adopted effective January 1, 2009. Required disclosures were added to Note 13.

In June 2009 FASB ASC 810-10-05-8 was issued. It requires reporting entities to evaluate former Qualifying Special Purpose Entities or QSPEs for consolidation, changes the approach to determining a variable interest entity's (VIE) primary beneficiary from a quantitative assessment to a qualitative assessment designed to identify a controlling financial interest, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. This statement requires additional year-end and interim disclosures for public and nonpublic companies that are similar to the disclosures required by FASB ASC 860-10-65-2. The statement is effective for fiscal years beginning after November 15, 2009 and for subsequent interim and annual reporting periods. The Company does not expect this statement to have a significant impact to its financial statements.

FASB ASC 855 was issued June 2009 and is effective for interim or annual financial periods ending after June 15, 2009 and addresses accounting and disclosure requirements related to subsequent events. The statement requires management to evaluate subsequent events through the date the financial statements are issued. Companies are required to disclose the date through which subsequent events have been evaluated. The Company has taken this statement into consideration in Note 19.

FASB ASC 825-10-65-1 requires publicly traded companies to disclose the fair value of financial instruments within the scope of FASB ASC 825 in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. FASB ASC 825-10-65-1 is effective for interim and annual periods ending after June 15, 2009. The Company has added the required footnote disclosure in interim financial statements.

(3) Public Offerings of Units by CELP and Certain Provisions of the Partnership Agreement

(a) Issuance of Common Units

On December 19, 2007, the Partnership issued 1,800,000 common units representing limited partner interests in the Partnership at a price of $33.28 per unit for net proceeds of $57.6 million. In addition, CEI made a general partner contribution of $1.2 million in connection with the issuance to maintain its 2% general partner interest. As a result of this offering, the Company recognized a gain of $7.5 million due to the Partnership issuing additional units at prices per unit greater than the Company's equivalent carrying value.

On April 9, 2008, the Partnership issued 3,333,334 common units in private offering at $30.00 per unit, which represented an approximate 7% discount from the market price. Net proceeds from the issuance, including our general partner contribution less expenses associated with the issuance, were approximately $102.0 million. As a result of this offering, the Company recognized a gain of $14.7 million due to the Partnership issuing additional units at prices per unit greater than the Company's equivalent carrying value.

(b) Conversion of Subordinated and Senior Subordinated Series C Units

The subordination period for the Partnership's subordinated units ended and the remaining 4,668,000 subordinated units converted into common units representing limited partner interests of the Partnership effective February 16, 2008. We own all 4,668,000 of the units that converted.

On June 29, 2006, the Partnership issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests of the units representing limited partner interest of all partnership in a private equity offering and proceeds of approximately $359.3 million. The senior subordinated series C units of the Partnership converted into common units representing limited partner interests of the Partnership effective February 16, 2008. The Company owns 6,414,830 of the senior subordinated series C units that converted to common units. The senior subordinated series C units were not entitled to distributions of available cash from the Partnership until conversion.

(c) Senior Subordinated Series D Units

On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests of the Partnership in a private offering. These senior subordinated series D units converted into common units representing limited partner interests of the Partnership on March 23, 2009. The Partnership did not make distributions of available cash from operating surplus, as defined in the partnership agreement, of at least $0.62 per unit on each outstanding common units for the quarter ending December 31, 2008, therefore each senior subordinated series D unit converted into 1.05 common units for a total issuance of 4,069,106 common units.

(d) Cash Distributions

Unless restricted by the terms of the Partnership's credit facility, the Partnership must make distributions of 100.0% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter commencing with the quarter ending on March 31, 2003. Distributions will generally be made 98.0% to the common and subordinated unitholders and 2.0% to the general partner, 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 its general partner is entitled to 13.0% of amounts the Partnership distributes in excess of $0.25 per unit, 23.0% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48.0% of amounts the Partnership distributes in excess of $0.375 per unit. No incentive distributions were earned by the general partner for the year ended December 31, 2009. Incentive distributions totaling $30.8 million, and $24.8 million were earned by the Company for the years ended December 31, 2008 and 2007, respectively. The Partnership paid annual per common unit distributions of $0.25, $2.36, and $2.28 in the years ended December 31, 2009, 2008 and 2007, respectively.

(e) Allocation of Partnership Income

Net income is allocated to Crosstex Energy GP, L.P., a wholly-owned subsidiary of the Company, as the Partnership's general partner in an amount equal to its incentive distributions as described in Note 3(d) above. The general partner's share of the Partnership's net income is reduced by stock-based compensation expense attributed to the Company's stock options and restricted stock awarded to officers and employees of the Partnership. The remaining net income after incentive distributions and Company-related stock-based compensation is allocated pro rata between the 2.0% general partner interest, the subordinated units (excluding senior subordinated units), and the common units. The following table reflects the Company's general partner share of the Partnership's net income (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Income allocation for incentive distributions	$ —	$ 30,772	$ 24,802
Stock-based compensation attributable to CEI's stock options and restricted shares	(2,966)	(4,665)	(5,441)
2.0% general partner interest in net income (loss)	2,147	308	(109)
General partner share of net income	$ (819)	$ 26,415	$ 19,252

The Company also owned limited partner common units, limited partner subordinated units and limited partner senior subordinated series C units in the Partnership. The Company's share of the Partnership's net income attributable to its limited partner common and subordinated units was a net income of $34.8 million and $5.9 million for the years ended December 31, 2009 and 2008 respectively, and a net loss of $2.0 million for the year ended December 31, 2007.

(4) Discontinued Operations, Impairments and Dispositions

(a) Discontinued Operations

The Partnership sold its Midstream assets in Alabama, Mississippi and south Texas for $217.6 million in August 2009. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $212.0 million were used to repay long-term indebtedness and the Partnership recognized a gain on sale of $97.2 million. On October 1, 2009, the Partnership sold its Treating assets for net proceeds of $265.4 million (after final purchase price adjustments). Sales proceeds, net of transaction costs and other obligations associated with the sale, of $258.1 million were used to repay long-term indebtedness and the Partnership recognized a gain on sale of $86.3 million.

In November 2008, the Partnership disposed of its undivided 12.4% interest in the Seminole gas processing plant to a third party for $85.0 million and recognized a gain of $49.8 million. This asset was previously presented in the Partnership's Treating segment and its values are included in the Treating revenues and net income from discontinued operations presented in the years ended December 31, 2008 and 2007 in the table below.

The revenues, operating expenses, general and administrative expenses associated directly with the sold assets, depreciation and amortization expense, Treating inventory impairment of $1.0 million during 2009, allocated Texas margin tax and an allocated interest expense related to the operations of the sold assets have been segregated from continuing operations and reported as discontinued operations for all periods. Interest expense of $34.4 million, $29.2 million and $32.7 million for the years ended December 31, 2009, 2008 and 2007, respectively, was allocated to discontinued operations related to the debt repaid from the proceeds from the asset dispositions using average historical interest rates for each of the three years. The interest allocation for 2009 also included make-whole interest payments and the write-off of unamortized debt issue costs related to the debt repaid. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are revenues and income from discontinued operations (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Midstream revenues	$ 368,142	$ 1,766,101	$ 1,411,092
Treating revenues	$ 45,534	$ 73,492	$ 65,025
Income (loss) from discontinued operations, net of tax	$ (1,519)	$ 21,466	$ 26,817
Gain from sale of discontinued operations, net of tax	$ 159,961	$ 42,753	$ —

(b) Other Dispositions

In November 2008, the Partnership sold a contract right for firm transportation capacity on a third party pipeline to an unaffiliated third party for $20.0 million. The entire amount of such proceeds is reflected in other income in the consolidated statement of operations.

(c) Long-Lived Asset Impairments

Impairments of $2.9 million and $24.6 million were recorded in the year ended December 31, 2009 and 2008, respectively related to long-lived assets. During 2009, impairments totaling $2.9 million were taken on the Bear Creek processing plant and the Vermillion treating plant to bring the fair value of the plants to a marketable value for these idle assets. The impairment expense during 2008 was:

- $17.8 million related to the Blue Water gas processing plant located in south Louisiana — The impairment on the Partnership's 59.27% interest in the Blue Water gas processing plant was recognized because the pipeline company which owns the offshore Blue Water system and supplies gas to the Partnership's Blue Water plant reversed the flow of the gas on its pipeline in early January 2009 thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system. At this time, the Partnership has not found an alternative source of new gas for the Blue Water plant so the plant ceased operations in January 2009. An impairment of $17.8 million was recognized for the carrying amount of the plant in excess of the estimated fair value of the plant as of December 31, 2008. The fair value of the Blue Water plant was determined by using the market and cost approach for valuing the plant. The income approach was not considered because the plant is not in operation.

- $4.1 million related to leasehold improvements — The Partnership had planned to relocate its corporate office during 2008 to a larger office facility. The Partnership had leased office space and was close to completing the renovation of this office space when the global economic decline began impacting its operations in October 2008. On December 31, 2008, the decision was made to cancel the new office lease and not relocate the corporate offices from its existing office location. The impairment relates to the leasehold improvements on the office space for the cancelled lease.

- $2.6 million related to the Arkoma gathering system — The impairment on the Arkoma gathering system was recognized because the Partnership sold this asset in February 2009 for approximately $10.7 million and the carrying amount of the asset exceeded the sale price by approximately $2.6 million.

(5) Goodwill

Goodwill on the Company's books as of December 31, 2008 related solely to the Treating assets which were sold in October 2009. In the fourth quarter of 2008, the Company determined that the carrying amount of goodwill attributable to the Midstream segment was impaired because of the significant decline in its Midstream operations. As a result, the Company recognized an impairment loss of $5.7 million in the Midstream segment for the year ended December 31, 2008.

(6) Investment in Limited Partnerships and Note Receivable

The Partnership owns a majority interest in Crosstex Denton County Joint Venture (CDC) and consolidates its investment in CDC pursuant to FASB ASC 810-10-05-8. The Partnership manages the business affairs of CDC. The other joint venture partner (the CDC partner) is an unrelated third party who owns and operates a natural gas field located in Denton County, Texas.

In connection with the formation of CDC, the Partnership agreed to loan the CDC Partner up to $1.5 million for their initial capital contribution. The loan bears interest at an annual rate of prime plus 2.0%. CDC makes payments directly to the Partnership attributable to CDC Partner's majority share of distributable cash flow to repay the loan. The balance remaining on the note of less than $0.1 million is included in current notes receivable as of December 31, 2009. The note was completely repaid in February 2010.

(7) Long-Term Debt

As of December 31, 2009 and 2008, long-term debt consisted of the following (in thousands):

	2009	2008
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2009 and 2008 were 6.75% and 3.9%, respectively	$529,614	$ 784,000
Senior secured notes (including PIK notes as defined below of $9.5 million), weighted average interest rates at December 31, 2009 and 2008 of 10.5% and 8.0%, respectively	326,034	479,706
Series B secured note assumed in the Eunice transaction, which bears interest at the rate of 9.5%	18,054	—
	873,702	1,263,706
Less current portion	(28,602)	(9,412)
Debt classified as long-term	$845,100	$1,254,294

Maturities. Maturities for the long-term debt as of December 31, 2009 are as follows (in thousands):

2010	28,602
2011	578,197
2012	93,000
2013	83,630
2014	67,380
Thereafter	22,893

The balance of the bank credit facility and senior secured notes was paid in full February 10, 2010 with the proceeds from the new credit facility and the senior unsecured notes.

Credit Facility. As of December 31, 2009, the Partnership had a bank credit facility with a borrowing capacity of $859.9 million that matures in June 2011. As of December 31, 2009, $683.0 million was outstanding under the bank credit facility, including $153.4 million of letters of credit, leaving approximately $176.9 million available for future borrowing.

New Credit Facility. In February 2010, the Partnership amended and restated its existing secured bank credit facility with a new syndicated secured bank credit facility (the "new credit facility"). The new credit facility has a borrowing capacity of $420.0 million and matures in February 2014. Net proceeds from the new credit facility along with net proceeds from the senior unsecured notes discussed under "Senior Unsecured Notes" below were used to, among other things, retire the Partnership's existing indebtedness.

The new credit facility will be guaranteed by substantially all of the Partnership's subsidiaries. Obligations under the new credit facility will be secured by first priority liens on substantially all of the Partnership's 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 the Partnership's equity interests in substantially all of its subsidiaries.

The Partnership may prepay all loans under the new credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The new credit facility will require 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 will not require any reduction of the lenders' commitments under the new credit facility.

Under the new credit facility, borrowings will bear interest at the Partnership's 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. The Partnership will pay a per annum fee on all letters of credit issued under the new credit facility, and a commitment fee of 0.50% per annum on the unused availability under the new credit facility. The letter of credit fee and the applicable margins for its interest rate will vary quarterly based on the leverage ratio (as defined in the new 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 will be as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letter of Credit Fees
Greater than or equal to 5.00 to 1.00	3.25%	4.25%	4.25%
Greater than or equal to 4.50 to 1.00 and less than 5.00 to 1.00	3.00%	4.00%	4.00%
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	2.75%	3.75%	3.75%
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	2.50%	3.50%	3.50%
Less than 3.50 to 1.00	2.25%	3.25%	3.25%

Based on the forecasted leverage ratio for 2010, the Partnership expects the applicable margin for the interest rate and letter of credit fee to be at the higher end of these ranges. The new credit facility will not have a floor for the Base Rate or the Eurodollar Rate.

The new credit facility includes financial covenants that will be tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter (except for the interest coverage ratio, which builds to a four-quarter test during 2010).

The maximum permitted leverage ratio will be as follows:

- 5.75 to 1.00 for the fiscal quarters ending March 31, 2010 and June 30, 2010;
- 5.50 to 1.00 for the fiscal quarter ending September 30, 2010;
- 5.25 to 1.00 for the fiscal quarter ending December 31, 2010;
- 5.00 to 1.00 for the fiscal quarter ending March 31, 2011;
- 4.75 to 1.00 for the fiscal quarter ending June 30, 2011; and
- 4.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

The maximum permitted senior leverage ratio (as defined in the new 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), will be 2.50 to 1.00.

The minimum consolidated interest coverage ratio (as defined in the new 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) will be as follows:

- 1.50 to 1.00 for the fiscal quarter ending March 31, 2010;
- 1.75 to 1.00 for the fiscal quarters ending June 30, 2010 through December 31, 2010;
- 2.00 to 1.00 for the fiscal quarter ending March 31, 2011;
- 2.25 to 1.00 for the fiscal quarter ending June 30, 2011; and
- 2.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

In addition, the new credit facility will contain various covenants that, among other restrictions, will limit the Partnership's ability to:

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

The new credit facility will permit the Partnership to make quarterly distributions to unitholders so long as no default exists under the new credit facility.

Each of the following will be an event of default under the new 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 new credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- the Partnership 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 new credit facility).

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

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

The Partnership will be subject to interest rate risk on its new credit facility and may enter into interest rate swaps to reduce this risk.

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

Senior Secured Notes. The Partnership entered into a master shelf agreement with an institutional lender in 2003 that was amended in subsequent years to increase availability under the agreement, pursuant to which it issued the following senior secured notes (dollars in thousands):

Month Issued	Amount	Interest Rate
June 2003	$ 1,607	9.45%
July 2003	1,000	9.38%
June 2004	50,629	9.46%
November 2005	57,380	8.73%
March 2006	40,504	8.82%
July 2006	165,390	9.46%
Total Outstanding	316,510	
PIK Notes Payable (1)	9,524	
Balance as of December 31, 2009 (2)	$ 326,034	

(1) The senior secured notes began accruing additional interest of 1.25% per annum in February 2009 (the "PIK notes") in the form of an increase in the principal amounts unless our leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter.

(2) The balance of senior secured notes was paid in full on February 10, 2010.

Series B Secured Note. On October 20, 2009, the Partnership acquired Eunice natural gas liquids processing plant and fractionation facility which includes $18.1 million in series B secured note. This note bears an interest rate of 9.5%. Payments including interest of $12.2 million and $7.4 million are due in 2010 and 2011, respectively.

Senior Unsecured Notes. On February 10, 2010, the Partnership issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "notes") due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under the credit facility discussed above, were used to repay in full amounts outstanding under the existing 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 existing credit facility. The notes are unsecured and unconditionally guaranteed on a senior basis by certain of our direct and indirect subsidiaries, including all of the Partnership's current subsidiaries other than Crosstex LIG, LLC and Crosstex Tuscaloosa, LLC, our Louisiana regulated entities, and Crosstex DC Gathering, J.V. Interest payments will be paid semi-annually in arrears starting on August 15, 2010.

The indenture governing the notes contains covenants that, among other things, will limit the Partnership's ability and the ability of certain of the Partnership's subsidiaries to:

- sell assets including equity interests in its subsidiaries;
- pay distributions on, redeem or repurchase or units or redeem or repurchase its subordinated debt;
- make investments;
- incur or guaranteed 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.

If the notes achieve an investment grade rating from each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services, many of these covenants will terminate.

The Partnership may redeem up to 35% of the notes at any time prior to February 15, 2013 with the cash proceeds from equity offerings at a redemption price of 108.875%, provided that:

- at least 65% of the aggregate principal amount of the senior notes remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 120 days of the date of the closing of the equity offering.

The Partnership has the option to redeem all or a portion of the notes at any time on or after February 15, 2014, at a redemption price (expressed as a percentage of principal amount) of:

- 104.438% in 2014;
- 102.219% in 2015; and
- 100.000% in 2016 and thereafter.

Prior to February 15, 2014, the Partnership may redeem the notes, in whole or in part, at a “make-whole” redemption price.

Each of the following will be 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; and
- the Partnership 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 unsecured 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 unsecured notes may accelerate the maturity of the senior unsecured notes and exercise other rights and remedies.

(8) 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):

	Years Ended December 31, 2009	2008
Compressor equipment	$ 27,192	$ 28,890
Less: Accumulated amortization	(3,655)	(1,523)
Net assets under capital lease	$ 23,537	$ 27,367

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, 2009 (in thousands):

Fiscal Year	
2010 through 2014	$ 15,200
Thereafter	12,746
Less: Interest	(4,147)
Net minimum lease payments under capital lease	23,799
Less: Current portion of net minimum lease payments	(3,002)
Long-term portion of net minimum lease payments	$ 20,797

(9) Income Taxes

The Company 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).

	2009	2008	2007
Current tax provision	$ 3,394	$ 2,593	$ 711
Deferred tax provision	15,229	7,022	10,338
	$ 18,623	$ 9,615	$ 11,049

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

	2009	2008	2007
Federal income tax at statutory rate (35)%	$ 11,993	$ 11,847	$ 8,129
State income taxes, net	709	1,329	682
Tax basis adjustment in Partnership related to issuance of common units	4,475	(5,209)	2,118
Non-deductible expenses	235	510	144
Other	1,211	1,138	(24)
Tax provision	$ 18,623	$ 9,615	$ 11,049

The following table summarizes the components of the income tax provision (in thousands):

	Years Ended December 31, 2009	2008	2007
From continuing operations	$ (6,020)	$ (1,375)	$ 6,319
From discontinued operations	24,643	10,990	4,730
Total tax provision	$ 18,623	$ 9,615	$ 11,049

The principal components of the Company's net deferred tax liability are as follows (in thousands):

	Years Ended December 31, 2009	2008
Deferred income tax assets:		
Net operating loss carryforward — current	$ —	$ 41
Net operating loss carryforward — non-current	18,148	40,310
Investment in the Partnership	8,013	3,892
Other comprehensive income	361	—
Alternative minimum tax carry forward (AMT)	1,241	41
	27,763	44,284
Less: valuation allowance	(8,013)	(3,892)
	19,750	40,392
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets — current	(501)	(501)
Property, plant, equipment, and intangible assets — non-current	(114,524)	(121,457)
Other comprehensive income	—	(367)
Other	(497)	(524)
	(115,522)	(122,849)
Net deferred tax liability	$ (95,772)	$ (82,457)

At December 31, 2009, the Company had a net operating loss carryforward of approximately $47.5 million that expires from 2026 through 2028. The Company also has various state net operating loss carryforwards of approximately $30.1 million which will begin expiring in 2021. Management believes that it is more likely than not that the future results of operations will generate sufficient taxable income to utilize these net operating loss carryforwards before they expire. Although the Company has generated net operating losses in the past, the Company expects to have future taxable income from its investment in the Partnership, generated by the remedial allocations of income among the unitholders and the income generated by operations.

Deferred tax liabilities relating to property, plant, equipment and intangible assets represent, primarily, the Company's share of the book basis in excess of tax basis for assets inside of the Partnership. The Company has also recorded a deferred tax asset in the amount of $8.0 million relating to the difference between its book and tax basis of its investment in the Partnership. Because the Company can only realize this deferred tax asset upon the liquidation of the Partnership and to the extent of capital gains, the Company has provided a full valuation allowance against this deferred tax asset. The deferred tax asset and the related valuation allowance increased $4.1 million in 2009 due to the conversion of the Partnership's senior subordinated series D units to common units.

Effective as of January 1, 2007, the Company is subject to the Texas margin tax. The new tax law had no significant impact on the Company's 2009 net deferred tax liability.

The Company adopted the provisions of FASB ASC 740-10-25-16 on January 1, 2007. A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (In thousands):

Balance as of December 31, 2007	$ —
Increases related to prior year tax positions	569
Increases related to current year tax positions	451
Balance as of December 31, 2008	1,020
Increases related to prior year tax positions	242
Increases related to current year tax positions	704
Balance as of December 31, 2009	$ 1,966

Unrecognized tax benefit of $2.0 million, if recognized, would affect the effective tax rate. Resolution of this uncertain issue is expected in 2010. In the event additional interest and penalties are incurred prior to resolution, per company policy, such penalties and interest will be recorded to income tax expense.

At December 31, 2009, tax years 2006 through 2009 remain subject to examination by the Internal Revenue Services and tax years 2005 through 2009 remain subject to examination by various state taxing authorities.

(10) Retirement Plans

The Company sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The Partnership makes contributions at each compensation calculation period based on the annual discretionary contribution rate. Contributions to the plan for the years ended December 31, 2009, 2008 and 2007 were $3.1 million, $3.4 million and $1.6 million, respectively.

(11) Employee Incentive Plans

(a) Long-Term Incentive Plan

In December 2002, the Partnership adopted 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 board of directors. The units issued upon exercise or vesting are newly issued units.

(b) Partnership 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, its general partner, or its general partner's general partner.

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 2009, 2008 and 2007 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, 2009 is provided below:

Crosstex Energy, L.P. Restricted Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	544,067	$ 31.90
Granted	1,971,127	3.92
Vested*	(239,719)	17.34
Forfeited	(187,470)	10.64
Non-vested, end of period	2,088,005	$ 7.31
Aggregate intrinsic value, end of period (in thousands)	$ 17,957	

* Vested units include 56,067 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued performance-based restricted units in 2007 and 2008 to executive officers. The minimum level of performance-based awards is included in restricted units outstanding and is included in the current share-based compensation cost calculations at December 31, 2009. The achievement of greater than the minimum performance targets in the current business environment is less than probable. All performance-based awards are subject to reevaluation and adjustment until the restricted units vest.

The Partnership awarded 803,632 restricted unit grants during the year ended December 31, 2009 to certain of the management team. Half of these units vest January 1, 2010. The remaining fifty percent of the units are performance-based awards that vest January 1, 2010 if the Partnership achieves certain performance metrics. As of December 31, 2009, the Partnership met the performance objectives stated in the grant with adjustments deemed necessary due to the disposition of assets in 2009. The performance-based units are shown in the balance of outstanding restricted units and included in the current share-based compensation calculations for the year ended December 31, 2009.

A summary of the restricted units aggregate intrinsic value (market value at vesting date) and fair value (market value at date of grant) of units vested during the years ended December 31, 2009, 2008 and 2007 are provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, L.P. Restricted Units:	**2009**	**2008**	**2007**
Aggregate intrinsic value of units vested	$ 1,023	$ 5,907	$ 1,342
Fair value of units vested	$ 4,158	$ 6,815	$ 888

As of December 31, 2009, there was $7.3 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.3 years.

(c) Partnership 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, its general partner or its general partner's general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior to estimate expected forfeiture rates. The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant. The Partnership used the simplified method to calculate the expected term.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant. The unit options granted in 2009, 2008 and 2007 generally vest based on 3 years of service (one-third after each year of service). The following weighted average assumptions were used for the Black-Scholes option-pricing model for grants in 2009, 2008 and 2007:

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options Granted:	**2009**	**2008**	**2007**
Weighted average distribution yield	0%	7.15%	5.75%
Weighted average expected volatility	76.2%	30.0%	32.0%
Weighted average risk free interest rate	2.34%	1.81%	4.39%
Weighted average expected life	6 years	6 years	6 years
Weighted average contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$ 2.89	$ 3.48	$ 6.73

A summary of the unit option activity for the years ended December 31, 2009, 2008 and 2007 is provided below:

	Years Ended December 31,					
	2009		2008		2007	
	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	1,304,194	$ 30.64	1,107,309	$ 29.65	926,156	$ 25.70
Granted (b)	636,122	4.46	402,185	31.58	347,599	37.29
Issued in exchange	344,319	4.80	—	—	—	—
Rendered in exchange	(1,032,403)	31.34	—	—	—	—
Exercised	(2,013)	4.08	(56,678)	14.16	(90,032)	18.20
Forfeited	(328,295)	27.51	(90,208)	31.29	(67,688)	29.84
Expired	(39,088)	30.30	(58,414)	32.93	(8,726)	31.60
Outstanding, end of period	882,836	$ 6.43	1,304,194	$ 30.64	1,107,309	$ 29.65
Options exercisable at end of period	159,929	$ 12.51	540,782	$ 29.12	281,973	$ 28.05
Weighted average contractual term (years) end of period:						
Options outstanding	8.7	—	7.4	—	7.6	—
Options exercisable	4.5	—	6.5	—	7.1	—
Aggregate intrinsic value end of period (in thousands):						
Options outstanding	$ 3,143	—	$ (a)	—	$ 4,681	—
Options exercisable	$ 336	—	$ (a)	—	$ 1,322	—

(a) Exercise price on all outstanding options exceeds current market price.

(b) No options were granted with an exercise price less than or equal to market value at grant during 2009, 2008 and 2007.

In May 2009, the Partnership's unitholders approved an amendment to the Partnership's long-term incentive plan to allow an option exchange program. This option exchange program was offered to all eligible employees excluding executive officers and directors because options held by employees were "underwater," meaning the exercise price of the options were higher than the current market price of the common units. The terms of the offer included an exchange ratio of 3 old options for 1 replacement option with an exercise price of $4.80 per common unit (120% of the average closing sales price for five trading days prior to the date of grant) which will vest over 2 years (50% after year 1 and 50% after year 2). In June 2009, a total of 453 employees elected to exchange 1,032,403 old options for 344,319 replacement options pursuant to this option exchange program. There was no incremental compensation cost resulting from the modifications under this option exchange program.

A summary of the unit options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value (value per Black-Scholes option pricing model at date of grant) of units vested during the years ended December 31, 2009, 2008 and 2007 are provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options:	2009	2008	2007
Intrinsic value of units options exercised	$ 5	$ 746	$ 1,675
Fair value of units vested	$ 1,675	$ 279	$ 197

As of December 31, 2009, there was $1.5 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 2.2 years.

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

The Crosstex Energy, Inc. long-term incentive plans provide for the award of stock options and restricted stock (collectively, "Awards") for up to 7,190,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2010, approximately 2,230,800 shares remained available under the long-term incentive plans for future issuance to participants. A participant may not receive in any calendar year options 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 Company'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 2009, 2008 and 2007 generally cliff vest after three years of service. A summary of the restricted stock, which activity for the year ended December 31, 2009, is provided below:

Crosstex Energy, Inc. Restricted Shares:	Number of Shares	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	604,313	$ 27.62
Granted	1,157,454	4.48
Vested*	(258,377)	16.96
Forfeited	(111,417)	16.30
Non-vested, end of period	1,391,973	$ 9.37
Aggregate intrinsic value, end of period (in thousands)	$ 8,421	

* Vested shares include 75,821 shares withheld for payroll taxes paid on behalf of employees.

The Company issued performance-based restricted shares in 2007 and 2008 to executive officers. The minimum level of performance-based awards is included in restricted shares outstanding and is included in the current share-based compensation cost calculations at December 31, 2009. The achievement of greater than the minimum performance targets in the current business environment is less than probable. All performance-based awards are subject to reevaluation and adjustment until the restricted shares vest.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value (market value at date of grant) of shares vested during the years ended December 31, 2009, 2008 and 2007 are provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, Inc. Restricted Shares:	2009	2008	2007
Aggregate intrinsic value of shares vested	$ 1,038	$ 13,493	$ 3,067
Fair value of shares vested	$ 4,382	$ 7,382	$ 1,275

Restricted shares in CEI totaling 244,915 and 205,983 were issued to directors, officers and employees of the Partnership with a weighted-average grant-date fair value of $32.41 and $26.13 per share in 2008 and 2007, respectively. As of December 31, 2009 there was $6.4 million of unrecognized compensation costs related to non-vested CEI restricted stock. The cost is expected to be recognized over a weighted average period of 2.1 years.

CEI Stock Options

CEI stock options have not been granted since 2005. A summary of the stock option activity for the years ended December 31, 2009, 2008 and 2007, is provided below:

	Years Ended December 31,					
	2009		2008		2007	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding, beginning of period	67,500	$ 9.54	105,000	$ 8.45	120,000	$ 8.21
Exercised	—	—	(37,500)	6.50	(15,000)	6.50
Outstanding, end of period	67,500	$ 9.54	67,500	$ 9.54	105,000	$ 8.45
Options exercisable at end of period	67,500	$ 9.54	22,500	$ 11.05	37,500	$ 7.87

As of December 31, 2009, there were 30,000 exercisable outstanding CEI stock options at a weighted average exercise price of $13.33 attributable to the Partnership's officers and employees. On January 1, 2010 these outstanding stock options were forfeited.

A summary of the stock options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value (value per Black-Scholes option pricing model at date of grant) of units vested during the years ended December 31, 2009, 2008 and 2007 is provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, Inc. Stock Options:	**2009**	**2008**	**2007**
Intrinsic value of stock options exercised	$ —	$ 1,089	$ 366
Fair value of shares vested	$ 49	$ 38	$ 66

(12) Fair Value of Financial Instruments

The estimated fair value of the Company's financial instruments has been determined by the Company using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount the Company could realize upon the sale or refinancing of such financial instruments (in thousands).

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 10,703	$ 10,703	$ 13,959	$ 13,959
Trade accounts receivable and accrued revenues	207,655	207,655	341,853	341,853
Fair value of derivative assets	14,777	14,777	31,794	31,794
Accounts payable, drafts payable and accrued gas purchases	174,008	174,008	315,622	315,622
Long-term debt	873,702	872,340	1,263,706	1,158,351
Obligations under capital lease	23,799	22,399	27,896	27,269
Fair value of derivative liabilities	42,443	42,443	51,281	51,281

The carrying amounts of the Company'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's long-term debt was comprised of borrowings under a revolving credit facility totaling $529.6 million and $784.0 million as of December 31, 2009 and 2008, respectively, which accrues interest under a floating interest rate structure. Accordingly, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2009, the Partnership also had borrowings totaling $326.0 million under senior secured notes with a weighted average interest rate of 10.5% and a series B secured note with a fixed rate of 9.5%. The fair value of these borrowings as of December 31, 2009 and 2008 were adjusted to reflect current market interest rate for such borrowings as of December 31, 2009 and 2008, respectively. 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 counterparty as required under FASB ASC 820.

(13) Derivatives

Interest Rate Swaps

The Partnership is subject to interest rate risk on its credit facility and entered into interest rate swaps to reduce this risk. The Partnership originally entered into eight interest rate swaps to fix the three month Libor rate, prior to credit margin, at rates between 2.83% and 4.69% on notional amounts totaling $550.0 million with maturities as early as January 2009 and as late as October 31, 2011, as amended January 2008. In September 2008, the Partnership entered into four additional interest rate swaps to convert the floating rate portion of the original swaps on a notional amount of $450.0 million from three month LIBOR to one month LIBOR. These swaps were not designated as cash flow hedges and therefore the impact of the interest rate swaps on net income is included in other income (expense) in the consolidated statements of operations as a part of interest expense, net.

The Partnership originally elected to designate all but one of the original eight interest rate swaps as cash flow hedges for FASB ASC 815 accounting treatment resulting in unrealized gains and losses booked in accumulated other comprehensive income. As a result of the January 2008 amendments, these swaps were de-designated as cash flow hedges. The unrealized loss in accumulated other comprehensive income of $17.0 million at the de-designation date was to be reclassified to earnings over the remaining original terms of the swaps using the effective interest method. During 2009 the unrealized loss reclassified to earnings and included in other income (expense) as a part of interest expense, net, was $10.0 million which consisted of $6.7 million under the effective interest method and $3.3 million due to the Partnership's decision to reduce its credit facility in February 2010. The remaining unamortized balance in accumulated other comprehensive income is $0.6 million at December 31, 2009. This balance is associated with one swap of $50.0 million that as of December 31, 2009 the Partnership anticipated being in place to its original term.

The impact of the interest rate swaps on net income is included in other income (expense) in the consolidated statements of operations as a part of interest expense, net, as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Change in fair value of derivatives that do not qualify for hedge accounting	$ 797	$ (22,105)	$ (1,185)
Realized gains (losses) on derivatives	(19,044)	(4,608)	707
	$ (18,247)	$ (26,713)	$ (478)

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

	Years Ended December 31,	
	2009	2008
Fair value of derivative assets — current	$ —	$ 149
Fair value of derivative liabilities — current	(17,960)	(17,217)
Fair value of derivative liabilities — long-term	(6,768)	(18,391)
Net fair value of interest rate swaps	$ (24,728)	$ (35,459)

During the recapitalization of the Partnership in February 2010, all interest rates swaps held by the Partnership were settled and all remaining asset and liability balances on the books related to the interest rate swaps at December 31, 2009 have been removed and the impact of the transaction on net income has been included in other income (expense) in the first quarter of 2010.

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, marketing financial swaps, storage swaps, basis swaps, processing margin swaps, and liquids swaps. 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. Marketing financial swaps are similar to on-system financial swaps, but are entered into for customers not connected to the Partnership's systems. Storage swaps 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.

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

	Years Ended December 31,		
	2009	2008	2007
Change in fair value of derivatives that do not qualify for hedge accounting	$ 2,816	$ (246)	$ 1,197
Realized gains on derivatives	(6,139)	(13,352)	(7,918)
Ineffective portion of derivatives qualifying for hedge accounting	65	(72)	104
Net gains related to commodity swaps	$ (3,258)	$ (13,670)	$ (6,617)
Net gains included in income from discontinued operations	264	5,051	2,470
Gain on derivatives included in continuing operations	$ (2,994)	$ (8,619)	$ (4,147)

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

	Years Ended December 31,	
	2009	2008
Fair value of derivative assets — current, designated	$ 369	$ 13,714
Fair value of derivative assets — current, non-designated	8,743	13,303
Fair value of derivative assets — long term, non-designated	5,665	4,628
Fair value of derivative liabilities — current, designated	(2,536)	—
Fair value of derivative liabilities — current, non-designated	(9,841)	(11,289)
Fair value of derivative liabilities — long term, non-designated	(5,338)	(4,384)
Net fair value of derivatives	$ (2,938)	$ 15,972

Set forth below is the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at December 31, 2009 (all gas volumes are expressed in MMBtu's and liquids are expressed in gallons). The remaining terms of the contracts extend no later than December 2010 for derivatives, except for certain basis swaps that extend to March 2012. 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 comprehensive income until the related anticipated future cash flow is recognized in earnings. The ineffective portion is recorded in earnings immediately.

December 31, 2009		
Transaction Type	**Volume**	**Fair Value**
	(In thousands)	
*Cash Flow Hedges:**		
Liquids swaps (short contracts)	(11,033)	$ (2,536)
Liquids swaps (long contracts)	1,247	369
Total swaps designated as cash flow hedges		$ (2,167)
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	155	$ 1
Physical offsets to swing swap transactions (short contracts)	(155)	—
Swing swaps (short contracts)	(682)	(3)
Physical offsets to swing swap transactions (long contracts)	682	—
Basis swaps (long contracts)	61,831	11,766
Physical offsets to basis swap transactions (short contracts)	(3,194)	18,553
Basis swaps (short contracts)	(47,938)	(8,626)
Physical offsets to basis swap transactions (long contracts)	3,194	(18,582)
Third-party on-system financial swaps (long contracts)	72	(184)
Third-party on-system financial swaps (short contracts)	(74)	(41)
Processing margin hedges — liquids (short contracts)	(16,422)	(3,718)
Processing margin hedges — gas (long contracts)	1,714	92
Storage swap transactions (short contracts)	(360)	(29)
Total Mark to market derivatives		$ (771)

* All are gas contracts, volume in MMBtu's, except for processing margin hedges — liquids and liquids swaps (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 of $34.5 million would be reduced to $15.2 million due to the netting feature. If the counterparties failed to completely perform according to the terms of the contracts the maximum loss the Partnership would sustain is $15.2 million with other energy companies.

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	**2009**	**2008**	**2007**
Natural gas	$ 2,156	$ 63	$ 5,533
Liquids	9,707	(10,402)	(4,066)
Realized (gain) loss included in income from discontinued operations	(759)	3,127	(474)
	$ 11,104	$ (7,212)	$ 993

Natural Gas

As of December 31, 2009, there is no remaining balance in accumulated other comprehensive income related to natural gas.

Liquids

As of December 31, 2009, an unrealized derivative fair value net loss of $2.1 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this amount, a $2.1 million loss is expected to be reclassified into earnings through December 2010. 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 and processing margin 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, 2009	$ (1,098)	$ 316	$ 11	$ (771)

(14) 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 establishes 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 swaps and interest rate swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. The Partnership determines the value of interest rate swap contracts by utilizing inputs and quotes from the counterparties to these contracts. The reasonableness of these inputs and quotes is verified by comparing similar inputs and quotes from other counterparties as of each date for which financial statements are prepared. The Partnership's contracts are all level two contracts under FASB ASC 820.

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in thousands):

	Level 2
Interest rate swaps*	$ (24,728)
Commodity swaps*	(2,938)
Total	$ (27,666)

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income (loss) at each measurement date. Accumulated other comprehensive income (loss) also includes the unrealized losses on interest rate swaps of $17.0 million recorded prior to de-designation in January 2008, of which $16.4 million has been recognized in earnings through December 2009.

(15) Transactions with Related Parties -Distribution of Assets for Cash

During 2008 we transferred two inactive processing plants to the Partnership at net book value for a cash price of $0.4 million which represented the fair value of the plants.

(16) Commitments and Contingencies

(a) Leases — Lessee

The Partnership has operating leases for office space, office and field equipment. The Eunice plant operating lease is no longer included in lease obligations. The Partnership acquired the Eunice, NGL processing plant and fractionation facility in October 2009, and will no longer have the lease obligation to an outside third party.

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

2010	$ 15,888
2011	12,111
2012	9,299
2013	6,145
2014	4,702
Thereafter	8,419
	$ 56,564

Operating lease rental expense for the years ended December 31, 2009, 2008 and 2007 was approximately $30.7 million, $39.4 million and $27.9 million, respectively.

(b) Employment Agreements

Certain members of management of the Company are parties to employment contacts with the general partner of the Partnership. The employment agreements provide those senior managers with severance payments in certain circumstances and prohibit each such person from competing with the general partner of the Partnership or its affiliates for a certain period of time following the termination of such person's employment.

(c) Environmental Issues

The Partnership acquired the south Louisiana processing assets from the El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. On April 17, 2009, the Partnership completed the remediation and obtained written confirmation from the LDEQ that "no further action" was needed and that the impaired groundwater quality at the Cow Island gas processing facility site has been restored to the proper standard. This matter is now officially resolved.

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. The Company does not expect to incur any material liability with these sites. In addition, the Partnership has disclosed possible Clean Air Act monitoring deficiencies it has discovered to the Louisiana Department of Environmental Quality and is working with the department to correct these deficiencies and to address modifications to facilities to bring them into compliance. The Company does not expect to incur any material environmental liability associated with these issues.

(e) Other

The Company 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.

In December 2008, Denbury Onshore, LLC ("Denbury") initiated formal arbitration proceedings against Crosstex CCNG Processing Ltd. ("Crosstex Processing"), Crosstex Energy Services, L.P. ("Crosstex Energy"), Crosstex North Texas Gathering, L.P. ("Crosstex Gathering") and Crosstex Gulf Coast Marketing Ltd. ("Crosstex Marketing"), all wholly-owned subsidiaries of the Partnership, asserting a claim for breach of contract under a gas processing agreement. Denbury alleged damages in the amount of $16.2 million, plus interest and attorneys' fees. Crosstex denied any liability and sought to have the action dismissed. A three-person arbitration panel conducted a hearing on the merits in December 2009. At the close of the evidence at the hearing, the panel granted judgment for Crosstex on one of Denbury's claims, and on February 16, 2010, the panel granted judgment for Denbury on its remaining claims in the amount of $3.0 million plus interest, attorneys' fees and costs. The panel will conduct additional proceedings to determine the amount of attorneys' fees and costs, if any, that should be awarded to Denbury. The Company estimates that the total award will be between $3.0 million and $4.0 million at the conclusion of these additional proceedings. The Company has accrued $3.7 million in other current liabilities for this award as of December 31, 2009 and reflected the related expense in purchased gas costs.

At times, the Partnership's gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain provided under state law. As a result, the Partnership (or its subsidiaries) is a 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 several 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, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed the Partnership approximately \$6.2 million, including approximately \$3.9 million for June 2008 sales and approximately \$2.3 million for July 2008 sales. The Partnership believes the July sales of \$2.3 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to Crosstex for an administrative claim in the amount of \$2.3 but it remains subject to objection by the lenders' agent. The Partnership evaluated these receivables for collectibility and provided a valuation allowance of \$3.1 million and \$0.8 million during the years ended December 31, 2008 and 2009, respectively.

(17) Capital Stock

(a) Common Stock

In October 2006, the Company's stockholders approved an increase in the number of authorized shares of capital stock from 20 million shares, consisting of 19 million shares of common stock and 1 million shares of preferred stock, to 150 million shares, consisting of 140 million shares of common stock and 10 million shares of preferred stock.

(b) Earnings per Share and Anti-Dilutive Computations

Basic earnings per common share was computed by dividing net income by the weighted-average number of common shares outstanding for the periods presented. The computation of diluted earnings per common share further assumes the dilutive effect of common share options and restricted shares.

The following are the share amounts used to compute the basic and diluted earnings per share for the years ended December 31, 2009, 2008 and 2007 (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Basic shares:			
Weighted average common shares outstanding	46,476	46,298	45,988
Dilutive shares:			
Weighted average common shares outstanding	46,476	46,298	45,988
Dilutive effect of restricted shares	59	248	537
Dilutive effect of exercise of options	—	43	82
Dilutive shares	46,535	46,589	46,607

(18) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per share amount)				
2009:					
Revenues	$ 353,158	$ 349,255	$ 350,900	$ 405,777	$ 1,459,090
Operating income	$ 2,954	$ 6,289	$ 7,703	$ 2,995	$ 19,941
Discontinued operations — net of tax	$ 3,265	$ 3,908	$ 81,466	$ 69,803	$ 158,442
Net income (loss) attributable to the non-controlling partners	$ (9,205)	$ (6,223)	$ 48,872	$ 37,019	$ 70,463
Net income (loss) attributable to Crosstex Energy, Inc.	$ (8,842)	$ (3,086)	$ 15,466	$ 12,104	$ 15,642
Basic earnings per common share	$ (0.19)	$ (0.07)	$ 0.33	$ 0.26	$ 0.33
Diluted earnings per common share	$ (0.19)	$ (0.07)	$ 0.33	$ 0.25	$ 0.33
2008:					
Revenues	$ 799,761	$ 996,832	$ 855,687	$ 423,731	$ 3,076,011
Operating income (loss)	$ 11,799	$ 9,100	$ 3,932	$ (43,447)	$ (18,616)
Discontinued operations — net of tax	$ 4,765	$ 8,474	$ 5,302	$ 45,678	$ 64,219
Net income (loss) attributable to the non-controlling partners	$ (4,073)	$ 6,568	$ (6,966)	$ (4,999)	$ (9,470)
Net income (loss) attributable to Crosstex Energy, Inc.	$ 10,706	$ 17,452	$ 540	$ (4,465)	$ 24,233
Basic earnings (loss) per common share	$ 0.23	$ 0.37	$ 0.01	$ (0.09)	$ 0.52
Diluted earnings (loss) per common share	$ 0.23	$ 0.37	$ 0.01	$ (0.09)	$ 0.51

(19) Subsequent Events

The Company evaluated events subsequent to the year ended December 31, 2009 through the date of the issuance of the financial statements on February 26, 2010.

Sale of Preferred Units. On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units to the Blackstone / GSO Capital Solutions funds. The preferred units are priced at $8.50 per unit and are convertible at any time into common units on a one-for-one basis, subject to certain adjustments and to its right to force conversion of the preferred units if certain conditions are met. The preferred units will pay 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. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if the Partnership pays a cash distribution on common units.

Disposition of Assets. On January 19, 2010 the Partnership completed the sale of its east Texas assets to a third party for $40.0 million and will recognize a $14.0 million gain on disposition. These assets were not included in discontinued operations nor were they shown as assets held for sale at December 31, 2009 due to the fact that they were immaterial to the Partnership.

Long-Term Recapitalization. On February 10, 2010, the Partnership entered into a new $420.0 million senior secured revolving credit facility with a four-year term and completed the private placement of $725.0 million principal amount of 8.875% senior unsecured notes due February 15, 2018 in a private placement. The Partnership used the net proceeds from the senior unsecured notes offering, together with borrowings under its new credit facility, to repay all borrowings outstanding under its previous revolving credit facility, and retire its senior secured notes and to pay related fees, costs and expenses.

SCHEDULE I

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,923	$ 12,323
Prepaid expenses and other	—	463
Total current assets	9,923	12,786
Investment in the Partnership	306,793	276,221
Total assets	$ 316,716	$ 289,007
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Payable to the Partnership	$ 8	$ 110
Other accrued liabilities	1,384	197
Total current liabilities	1,392	307
Deferred tax liability	87,038	73,271
Stockholders' equity:		
Common stock	464	464
Additional paid-in capital	271,669	268,988
Retained earnings	(43,279)	(54,693)
Accumulated other comprehensive income (loss)	(568)	670
Total stockholders' equity	228,286	215,429
Total liabilities and stockholders' equity	$ 316,716	$ 289,007

See "Notes to Consolidated Financial Statements" of Crosstex Energy, Inc. included in this report.

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2009	2008	2007
	(In thousands except share data)		
Operating income and expenses:			
Income (loss) from investment in the Partnership	$ 33,875	$ 20,468	$ 17,202
Loss from investment in subsidiary	—	(139)	(35)
General and administrative expense	(2,584)	(3,429)	(2,776)
Impairment of goodwill	—	(804)	—
Operating income (loss)	31,291	16,096	14,391
Other income (expense):			
Interest and other income	48	238	410
Income (loss) before gain on issuance of units by the Partnership and income taxes	31,339	16,334	14,801
Gain on issuance of units in the Partnership	—	14,748	7,461
Income tax provision expense	(15,697)	(6,849)	(10,086)
Net income	$ 15,642	$ 24,233	$ 12,176
Net income per common share:			
Basic	$ 0.33	$ 0.52	$ 0.26
Diluted	$ 0.33	$ 0.51	$ 0.26
Weighted average common shares outstanding:			
Basic	46,476	46,298	45,988
Diluted	46,535	46,589	46,607

See "Notes to Consolidated Financial Statements" of Crosstex Energy, Inc. included in this report.

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 15,642	$ 24,233	$ 12,176
Adjustments to reconcile net income (loss) to net cash flow provided by (used in) operating activities:			
Income from investment in the Partnership, including discontinued operations	(33,929)	(20,428)	(17,202)
Loss from investment in subsidiary	—	139	35
Impairment	—	804	—
Deferred taxes	15,697	6,849	10,086
Stock-based compensation	113	36	(25)
Gain on issuance of units in the Partnership	—	(14,748)	(7,461)
Changes in assets and liabilities:			
Accounts receivable, prepaid expenses and other	463	(467)	68
Accounts payable and other accrued liabilities	(116)	118	116
Net cash used in operating activities	(2,130)	(3,464)	(2,207)
Cash flows from investing activities:			
Investment in the Partnership	(21)	(2,193)	(4,014)
Distributions from the Partnership	4,333	76,026	47,565
Contributions to subsidiary	—	(139)	(35)
Net cash provided by investing activities	4,312	73,694	43,516
Cash flows from financing activities:			
Proceeds from exercise of common stock options	—	244	98
Conversion of restricted stock, net of shares withheld for taxes	(354)	(3,815)	(919)
Common dividends paid	(4,228)	(62,048)	(42,588)
Net cash used in financing activities	(4,582)	(65,619)	(43,409)
Net increase (decrease) in cash	(2,400)	4,611	(2,100)
Cash, beginning of year	12,323	7,712	9,812
Cash, end of year	$ 9,923	$ 12,323	$ 7,712

See "Notes to Consolidated Financial Statements" of Crosstex Energy, Inc. included in this report.

SCHEDULE II

CROSSTEX ENERGY, INC.
VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In thousands)		
Year Ended December 31, 2009:				
Allowance for doubtful accounts	$ 3,655	$ 1,070	$ 4,315	$ 410
Year Ended December 31, 2008:				
Allowance for doubtful accounts	$ 985	$ 2,670	$ —	$ 3,655
Year Ended December 31, 2007:				
Allowance for doubtful accounts	$ 618	$ 367	$ —	$ 985