
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, 2005

OR

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

Commission file number: 000-50067

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

Delaware *(State of organization)*	**16-1616605** *(I.R.S. Employer Identification No.)*
2501 CEDAR SPRINGS **DALLAS, TEXAS** *(Address of principal executive offices)*	**75201** *(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
None	Not applicable

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

Title of Class
Common Units Representing Limited Partnership Interests

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 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

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

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $304,925,000 on June 30, 2005, based on $38.05 per unit, the closing price of the Common Units as reported on the NASDAQ National Market on such date.

At February 24, 2006, there were outstanding 19,562,144 Common Units and 7,001,000 Subordinated Units.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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DESCRIPTION

CROSSTEX ENERGY, L.P.

PART I

Item 1. *Business*

General

Crosstex Energy, L.P. is a publicly traded Delaware limited partnership, formed in July 2002 in connection with its initial public offering, which was completed in December 2002. Our Common Units are listed on the NASDAQ National Market. Our business activities are conducted through our subsidiary, Crosstex Energy Services, L.P., a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership. Our executive offices are located at 2501 Cedar Springs, Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.crosstexenergy.com. In the Investor Information 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 terms "Partnership" and "Registrant," as well as the terms "our," "we" and "its," are sometimes used as abbreviated references to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. and its consolidated subsidiaries, including the Operating Partnership.

We are an independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids, or NGLs. We connect the wells of natural gas producers in our market areas to our gathering systems, treat natural gas to remove impurities to ensure that it meets pipeline quality specifications, process natural gas for the removal of NGLs, fractionates natural gas liquids into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipelines and thereby generate gross margins based on the difference between the purchase and resale prices. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering lines under a variety of fee arrangements.

We have two operating segments, Midstream and Treating. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and natural gas liquids, while our Treating division focuses on the removal of impurities from natural gas to meet pipeline quality specifications. On November 1, 2005, we acquired El Paso Corporation's natural gas processing and liquids business in south Louisiana, which we refer to as the El Paso Acquisition, significantly expanding our midstream presence in that area. Following this acquisition, our primary midstream assets include approximately 5,000 miles of natural gas gathering and transmission pipelines, nine natural gas processing plants and four fractionators. Our 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. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. Our processing plants remove NGLs from a natural gas stream and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso- and normal butanes and natural gasoline. Our primary treating assets include approximately 190 natural gas treating plants. Our natural gas treating plants remove carbon dioxide and hydrogen sulfide from natural gas prior to delivering the gas into pipelines to ensure that it meets pipeline quality specifications. See Note 13 to the consolidated financial statements for financial information about these operating segments.

Set forth in the table below is a list of our significant acquisitions since January 1, 2003.

Acquisition	Acquisition Date	Purchase Price (In thousands)	Asset Type
DEFS Acquisition	June 2003	$ 68,124	Gathering and transmission systems and processing plants
LIG Acquisition	April 2004	73,692	Gathering and transmission systems and processing plants
Crosstex Pipeline Partners	December 2004	5,100	Gathering pipeline
Graco Operations	January 2005	9,257	Treating plants
Cardinal Gas Services	May 2005	6,710	Treating plants and gas processing plants
El Paso Acquisition	November 2005	480,976	Processing and liquids business
Hanover Amine Treating	February 2006	51,500	Treating plants

Our general partner interest is held by Crosstex Energy GP, L.P., a Delaware limited partnership. Crosstex Energy GP, LLC, a Delaware limited liability company, is Crosstex Energy GP, L.P.'s general partner. Crosstex Energy GP, LLC manages our operations and activities and employs our officers.

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

/d = per day
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

Business Strategy

Our strategy is to increase distributable cash flow per unit by making accretive acquisitions of assets that are essential to the production, transportation, and marketing of natural gas and NGLs; improving the profitability of our owned assets by increasing their utilization while controlling costs; accomplishing economies of scale through new construction or expansion in core operating areas; and maintaining financial flexibility to take advantage of opportunities. We will also build new assets in response to producer and market needs, such as our North Texas Pipeline project as discussed below. We believe the expanded scope of our operations, combined with a continued high level of drilling in our principal geographic areas, should present opportunities for continued expansion in our existing areas of operation as well as opportunities to acquire or develop assets in new geographic areas that may serve as a platform for future growth. Key elements of our strategy include the following:

- *Pursuing accretive acquisitions.* We intend to use our acquisition and integration experience to continue to make strategic acquisitions of midstream assets that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of the acquired asset. We pursue acquisitions that we believe will add to existing core areas in order to capitalize on our existing infrastructure, personnel, and producer and consumer relationships. For example, we believe the El Paso Acquisition complements our existing asset base in Louisiana and provides opportunities for asset optimization and cost savings opportunities. We also examine opportunities to establish new core areas in regions with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas. We plan to establish new core areas primarily through the acquisition or development of key assets that will serve as a platform for further growth both through additional acquisitions and the construction of new assets. We established new core areas through the acquisition and consolidation of our south Texas assets in 2001 through 2003 and the acquisition of LIG Pipeline Company and its subsidiaries, which we collectively refer to as LIG, in 2004. We are now working to consolidate the El Paso Acquisition with LIG to develop operating synergies.

- *Improving existing system profitability.* After we acquire or construct a new system, we begin an aggressive effort to market services directly to both producers and end users in order to connect new supplies of natural gas, improve margins, and more fully utilize the system's capacity. As part of this process, we focus on providing a full range of services to small and medium size independent producers and end users, including supply aggregation, transportation and hedging, which we believe provides us with a competitive advantage when we compete for sources of natural gas supply. Since treating services are not provided by many of our competitors, we have an additional advantage in competing for new supply when gas requires treating to meet pipeline specifications. Additionally, we emphasize increasing the percentage of our natural gas and natural gas liquids sales directly to end users, such as industrial and utility consumers, in an effort to increase our operating margins.
- *Undertaking construction and expansion opportunities ("organic growth").* We leverage our existing infrastructure and producer and customer relationships by constructing and expanding systems to meet new or increased demand for our gathering, transmission, treating, processing and marketing services. These projects include expansion of existing systems and construction of new facilities, which has driven the growth of the Treating division in recent years. In 2005, we began construction on a new 143-mile pipeline to transport gas from an area near Fort Worth, Texas, where recent drilling activity in the Barnett Shale formation has expanded production beyond the existing infrastructure capability. We refer to this project as our North Texas Pipeline project and expect that it will commence operations in the first quarter of 2006. Once completed, the pipeline will allow curtailed gas to flow to markets that are currently not available to some key Barnett Shale producers. We are currently evaluating several similar projects in Texas and Louisiana.

Recent Acquisitions and Expansion

El Paso Corporation processing and liquids business. On November 1, 2005 we acquired the south Louisiana processing and liquids business of El Paso Corporation for $481.0 million. The acquired assets include 2.3 Bcf/d of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage, and approximately 400 miles of liquids transport lines. We believe the El Paso Acquisition provides us with several key strategic benefits, including:

- the opportunity to participate in the growing development of deepwater Gulf of Mexico reserves;
- the opportunity to establish a significant presence in the natural gas liquids marketing business;
- the opportunity to realize operating efficiencies with our existing asset base in Louisiana, including the ability to shift processing from some of our plants acquired with the LIG system to plants acquired from El Paso that have additional capacity, reducing overall operating costs and freeing certain LIG assets to be redeployed to underserved markets; and
- a larger business platform from which we can grow our midstream operations.

Graco Operations. In January 2005, we acquired all of the assets of Graco Operations for $9.26 million. The acquisition added approximately 25 treating plants and related inventory.

Cardinal Gas Services. We acquired the treating and gas processing operations of Cardinal Gas Services as of May 1, 2005 for $6.7 million. The acquisition added nine treating plants and 19 dewpoint control plants. This acquisition allowed us to extend our service capabilities into the dewpoint suppression business.

North Texas Pipeline Project. In 2005, we began construction on a new 143-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas. This project connects production from the Barnett Shale to markets in north Texas and to markets accessed by the NGPL pipeline and other pipelines that we connect with. Drilling success in the Barnett Shale formation in the area has expanded production beyond the capacity of the existing pipeline infrastructure. Capital costs to construct the pipeline and associated facilities are estimated to be approximately $115 million, with completion estimated in the first quarter of 2006. The pipeline will allow contracted gas to flow to markets that are currently not available to some key Barnett Shale producers.

Hanover Acquisition. On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.5 million. After this acquisition we have approximately 150 treating plants in operation and a total fleet of approximately 190 units.

Other Developments

June 2005 Sale of Senior Subordinated Units. In June 2005, we issued 1,495,410 senior subordinated units in a private offering for net proceeds of $51.1 million, including our general partner's $1.1 million capital contribution and after expenses associated with the sale. The senior subordinated units were issued at $33.44 per unit, which represented a discount of 13.7% to the market value of common units on such date, and automatically converted into common units on a one-for-one basis on February 24, 2006. The senior subordinated units were not entitled to distributions of available cash until their conversion to common units.

November 2005 Sale of Senior Subordinated B Units. On November 1, 2005, we issued 2,850,165 Senior Subordinated Series B Units in a private placement for a purchase price of $36.84 per unit. We received net proceeds of approximately $107.1 million, including our general partner's $2.1 million capital contribution and after expenses associated with the sale. The Senior Subordinated Series B Units automatically converted into common units on November 14, 2005 on a one-for-one basis. The Senior Subordinated Series B Units were not entitled to distributions paid on November 14, 2005. The net proceeds were used to fund a portion of the El Paso Acquisition.

November 2005 Public Offering. In November and December 2005, we issued 3,731,050 common units to the public at a purchase price of $33.25 per unit. The offering resulted in net proceeds to us of approximately $120.9 million, including the general partner's $2.5 million capital contribution and after expenses associated with the offering.

Bank Credit Facility. On November 1, 2005, we amended our bank credit facility to, among other things, provide for revolving credit borrowings up to a maximum principal amount of $750 million and the issuance of letters of credit in the aggregate face amount of up to $300 million, which letters of credit reduce the credit available for revolving credit borrowings. The bank credit agreement includes procedures for additional financial institutions selected by us to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by us and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders. The maturity date was also extended to November 2010.

Senior Secured Notes. In November 2005, we completed a private placement of $85 million of senior secured notes pursuant to our master shelf agreement with institutional lenders with an interest rate of 6.23% and a maturity of ten years. We used the net proceeds from this private placement to reduce the balance of our bank credit facility. As of December 31, 2005, borrowings under the master shelf agreement totaled $200.0 million.

Midstream Segment

Gathering, Processing and Transmission. Our primary Midstream assets include systems located primarily along the Texas Gulf Coast and in south-central Mississippi and in Louisiana, which, in the aggregate, consist of approximately 5,000 miles of pipeline, nine processing plants and four fractionators and contributed approximately 76% and 77% of our gross margin in 2005 and 2004, respectively.

- *El Paso Acquisition.* On November 1, 2005, we acquired El Paso Corporation's natural gas processing and liquids business in south Louisiana. The assets acquired include a total of 2.3 Bcf/d of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines.

  The primary facilities and other assets we acquired consist of:

  - *Eunice Processing Plant and Fractionation Facility.* The Eunice facilities are located near Eunice, Louisiana. The Eunice processing plant has a capacity of 1.2 Bcf/d and processed approximately 787 MMcf/d of natural gas for the nine months ended September 30, 2005 (prior to our acquisition and prior to the full impact of Hurricanes Rita and Katrina). In November and December 2005 (after our acquisition and the impacts of the hurricanes), the plant processed approximately 934 MMcf/d. The plant is connected to onshore, continental shelf and deepwater gas production and has downstream connections to the ANR Pipeline, Florida Gas Transmission and Texas Gas Transmission pipeline systems. The Eunice fractionation facility has a capacity of 36,000 barrels per day of liquid products. This facility also has 190,000 barrels of above-ground storage capacity. The fractionation facility produces ethane, propane, isobutane, normal butane and natural gasoline for customers such as Westlake, Econogas, Dufour, Ferrell Gas, Hercules and Marathon. The fractionation facility is directly connected to the Southeast propane market and pipelines to the Anse La Butte storage facility. In connection with the acquisition of this facility, we also acquired a three-year storage agreement with the Anse La Butte facility.

- *Pelican Processing Plant.* The Pelican processing plant complex is located in Patterson, Louisiana and has a designed processing capacity of 600 MMcf/d of natural gas. For the nine months ended September 30, 2005 (prior to our acquisition and prior to the full impact of Hurricanes Rita and Katrina), the plant processed approximately 311 MMcf/d. In November and December 2005 (after our acquisition and the impacts of the hurricanes), the plant processed approximately 226 MMcf/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 15 miles 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 and Transco. For the nine months ended September 30, 2005 (prior to our acquisition and prior to the full impact of Hurricanes Rita and Katrina), this facility processed approximately 235 MMcf/d. In November and December 2005 (after our acquisition and the impacts of the hurricanes), the plant processed approximately 125 MMcf/d.
- *Blue Water Gas Processing Plant.* We acquired a 23.85% interest in the Blue Water gas processing plant, which represents a net processing capacity to the acquired interest of 186 MMcf/d. Approximately 52 MMcf/d of our net capacity was being used in the nine months ended September 30, 2005 (prior to our acquisition and prior to the full impact of Hurricanes Rita and Katrina). In November and December 2005 (after our acquisition and the impacts of the hurricanes), approximately 21 MMcf/d was processed net to our interest. The Blue Water plant is located near Crowley, Louisiana and is operated by ExxonMobil. The Blue Water facility is connected to continental shelf and deepwater production volumes through the Blue Water pipeline system. Downstream connections from this plant include the Tennessee Gas Pipeline and Columbia Gulf. The facility also performs LNG conditioning services for the Excelerate Energy LNG tanker unloading facility.
- *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 28,000 to 30,000 barrels per day of liquids products and fractionates liquids delivered by the Cajun Sibon pipeline system from the Pelican, Blue Water and Cow Island plants or by truck. The Riverside facility has above-ground storage capacity of approximately 102,000 barrels.
- *Napoleonville Storage Facility.* The Napoleonville natural gas liquid storage facility is connected to the Riverside facility and has a total capacity of 2.4 million barrels of underground storage.
- *Cajun Sibon Pipeline System.* The Cajun Sibon pipeline system consists of 400 miles of 6-inch and 8-inch pipelines with a system capacity of 28,000 barrels per day. The pipeline transports raw make from the Pelican plant and the Blue Water plant to either the Riverside fractionator or the Napoleonville storage facility. Alternate deliveries can be made to the Eunice plant.

Hurricane Katrina struck the Coast of Louisiana and Mississippi in August 2005, after causing damage to Gulf of Mexico production and transmission facilities. Hurricane Rita struck the Gulf Coast of Texas and Louisiana in the last week of September 2005, also damaging production and transmission infrastructure, and causing minor damage to the Sabine Pass processing plant. El Paso bore the costs of the repairs to this plant, which is now complete, and the facility recommenced operations in December 2005. All other facilities were operational after minor clean-up from the storms, although throughput has not yet returned to levels we anticipated prior to the acquisition, as the offshore pipelines supplying natural gas to the facilities have experienced difficulties in making necessary infrastructure repairs. We expect those repairs to be completed over the course of the first and second quarters of 2006 and volumes to be substantially restored after that.

- *LIG System.* We acquired the LIG system on April 1, 2004. The LIG system is the largest intrastate pipeline system in Louisiana, consisting of 2,000 miles of gathering and transmission pipeline, and had an average throughput of approximately 613,000 MMBtu/d for the year ended December 31, 2005. The system also includes two operating processing plants with an average throughput of 300,000 MMBtu/d for the year ended December 31, 2005. The system has access to both rich and lean gas supplies. These supplies reach from north Louisiana to new offshore production in southeast Louisiana. 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 Texas System.* We have assembled a highly-integrated south Texas system comprised of approximately 1,400-miles of intrastate gathering and transmission pipelines and a processing plant with a processing capacity of approximately 150,000 Mcf/d. This system was built through a number of acquisitions and follow-on organic projects. The acquisitions were the Gulf Coast system, the Corpus Christi system, the Gregory gathering system and processing plant, the Hallmark system, and the Vanderbilt system. Average throughput on the system for the year ended December 31, 2005 was approximately 517,000 MMBtu/d. Average throughput in the processing plant was approximately 95,000 MMBtu/d for that period. The system gathers gas from major production areas in the Texas Gulf coast and delivers gas to the industrial markets, power plants, other pipelines, and gas distribution companies in the region from Corpus Christi to the Houston area.

Other midstream assets and activities:

- *Mississippi Pipeline System.* This 638-mile system in south Mississippi gathers wellhead supply in the region and sells it through direct market connections to utilities and industrial end-users. Average throughput on the system was approximately 83,000 MMBtu/d for the year ended December 31, 2005.
- *Arkoma Gathering System.* This 140-mile low-pressure gathering system in southeastern Oklahoma delivers gathered gas into a mainline transmission system. For the year ended December 31, 2005, throughput on the system averaged approximately 23,000 MMBtu/d.
- *Other.* Other midstream assets consist of a variety of gathering lines and a processing plant with a processing capacity of approximately 65,000 Mcf/d. Total volumes gathered and resold were approximately 65,000 MMBtu/d for the year ended December 31, 2005. Total volumes processed were approximately 23,000 MMBtu/d in the period.
- *Off-System Services.* We offer natural gas marketing services on behalf of producers for natural gas that does not move on our assets. We market this gas on a number of interstate and intrastate pipelines. These volumes averaged approximately 181,000 MMBtu/d in 2005.

Treating Segment

We operate treating plants which remove carbon dioxide and hydrogen sulfide from natural gas before it is delivered into transportation systems to ensure that it meets pipeline quality specifications. Our treating division contributed approximately 24% and 23% of our gross margin in 2005 and 2004, respectively. Our treating business has grown from 74 plants in operation at December 31, 2004 to 112 plants in operation at December 31, 2005. During 2005 we spent $16.0 million in two separate acquisitions to acquire 35 treating plants, 19 dewpoint control plants and related inventory. In February 2006 we acquired the amine treating assets of a subsidiary of Hanover Compression Company, increasing our total plants in operation to approximately 150 and our total fleet of treating plants to approximately 190.

We believe we have the largest gas treating operation in the Texas and Louisiana Gulf Coast. The treating plants remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced to transportation systems to ensure that it meets pipeline quality specifications. Natural gas from certain formations in the Texas Gulf Coast, as well as other locations, is high in carbon dioxide. Many of our active plants are treating gas from the Wilcox and Edwards formations in the Texas Gulf Coast, both of which are deeper formations that are high in carbon dioxide. In cases where producers pay us to operate the treating facilities, we either charge a fixed rate per Mcf of natural gas treated or charge a fixed monthly fee.

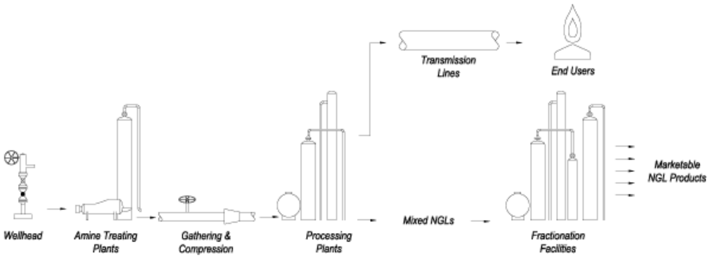
We also own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas, which we account for as part of our Treating Division. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon dioxide under a long-term arrangement. Revenues at the plant are derived from a fee it charges producers, primarily those at the Seminole San Andres unit, for each Mcf of carbon dioxide returned to the producer for reinjection. The fees currently average approximately $0.57 for each Mcf of carbon dioxide returned. The plant also receives 50% of the NGLs produced by the plant.

Our treating growth strategy is based on the belief that if gas prices remain at recent levels, producers will be encouraged to drill deeper gas formations. We believe the gas recovered from these formations is more likely to be high in carbon dioxide, a contaminant that generally needs to be removed before introduction into transportation pipelines. When completing a well, producers place a high value on immediate equipment availability, as they can more quickly begin to realize cash flow from a completed well. We believe our track record of reliability, current availability of equipment, and our strategy of sourcing new equipment gives us a significant advantage in competing for new treating business.

Treating process. The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. Amine has a chemical affinity for hydrogen sulfide and carbon dioxide that allows it to remove the impurities from the gas. After mixing, gas and reacted amine are separated and the impurities are removed from the amine by heating. Treating plants are sized by the amine circulation capacity in terms of gallons per minute.

Industry Overview

The following diagram illustrates the natural gas treating, 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-use 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 begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Our 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.

Natural gas treating. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is high in carbon dioxide. Treating plants are placed at or near a well and remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced into gathering systems and transmission pipelines to ensure that it meets pipeline quality specifications.

Natural gas processing and fractionation. 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 must 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 facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline.

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.

Supply/Demand Balancing

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

Competition

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

Our gas treating operations face competition from manufacturers of new treating and dewpoint control plants and from a small number of regional operators that provide plants and operations similar to ours. We also face competition from vendors of used equipment that occasionally operate plants for producers. In addition, we routinely lose business to gas gatherers who have underutilized treating or processing capacity and can take the producers' gas without requiring wellhead treating. We may also lose wellhead treating opportunities to blending. Some pipeline companies have the limited ability to waive their quality specifications and allow producers to deliver their contaminated gas untreated. This is generally referred to as blending because of the receiving company's ability to blend this gas with cleaner gas in the pipeline such that the resulting gas meets pipeline specification.

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

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

Natural Gas Supply

Our end-user pipelines have connections with major interstate and intrastate pipelines, which we believe have ample supplies of natural gas in excess of the volumes required for these systems. In connection with the construction and acquisition of our gathering systems, we evaluate well and reservoir data furnished by producers 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 our investment. Based on these facts, we believe that there should be adequate natural gas supply to recoup our investment with an adequate rate of return. We do not routinely obtain independent evaluations of reserves dedicated to our systems due to the cost and relatively limited benefit of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

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

During the year ended December 31, 2005, we had one customer that accounted for approximately 10.6% of our consolidated revenues. While this customer represents a significant percentage of consolidated revenues, the loss of this customer would not have a material impact on our results of operations.

Regulation

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

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- maximum rates payable for certain services;
- the initiation and discontinuation of services; and
- various other matters.

In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipelines’ rates and rules and policies that may affect rights of access to natural gas transportation capacity. Our intrastate natural gas pipeline operations generally are not subject to rate regulation by FERC, but the rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). 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 the FERC or by an appropriate state agency. Rates for interstate services provided under NGPA Section 311 on our Louisiana and Mississippi pipeline systems are each subject to review in 2006.

Intrastate Pipeline Regulation. Our intrastate natural gas pipeline operations generally are not subject to rate regulation by FERC, but they are subject to regulation by various agencies of the states in which they are located, principally the Texas Railroad Commission, or TRRC, and the Louisiana Department of Natural Resources Office of Conservation. 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.

Our operations in Texas are subject to the Texas Gas Utility Regulatory Act, as implemented by the TRRC. Generally the TRRC is vested with authority to ensure that rates charged for natural gas sales or transportation services are just and reasonable. Once set, the rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us or whether the TRRC will change its regulation of these rates.

We own a private line in New Mexico that is used to serve one customer, of which approximately one mile is regulated by the New Mexico Public Regulation Commission. Similarly, a twelve-mile section of our Mississippi gathering system is regulated by the Mississippi Oil and Gas Board as it transports gas not owned by us for a fee. The Arkoma gathering system in Oklahoma is regulated by the Oklahoma Corporation Commission. Similarly, gathering systems we own in Alabama are subject to regulation by the Alabama State Oil and Gas Board. Our LIG intrastate system is regulated by the Louisiana Department of Natural Resources Office of Conservation.

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

We are subject to 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. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels 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. For example, the TRRC has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Many of the producing states have adopted some form of complaint based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. The price at which we sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our 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 stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect less extensive regulation. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing operations, and we note that some of FERC's more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

Environmental Matters

General. Our operation of treating, processing and fractionation plants, pipelines and associated facilities in connection with the gathering, treating 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 our overall costs of doing business, including cost of planning, constructing, and operating plants, pipelines, and other facilities. Included in our 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. While we believe that we currently hold all material governmental approvals required to operate our major facilities, we are currently evaluating and updating permits for certain of our facilities specifically including those obtained in recent acquisitions. As part of the regular overall evaluation of our operations, we have implemented procedures and are presently working to ensure that all governmental approvals, for both recently acquired facilities and existing operations, are updated as may be necessary. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our 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 our possible future operations, and we cannot assure you that we will not incur significant costs and liabilities including those relating to claims for damage to property and persons as a result of such upsets, releases, or spills. In the event of future increases in costs, we may be unable to pass on those cost increases to our customers. A discharge of hazardous substances or wastes into the environment could, to the extent the event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to property. We will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly to comply with changing environmental laws and regulations and to minimize costs.

Hazardous Substance and Waste. To a large extent, the environmental laws and regulations affecting our possible future operations relate to the release of hazardous substances or solid wastes into soils, groundwater, and surface water, and include measures to control environmental pollution of the environment. 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. These 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 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, we may generate wastes that may fall within the definition of a "hazardous substance." We may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or any analogous state laws.

We also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. 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. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. However, 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 disposal requirements. Changes in applicable regulations may result in an increase in our capital expenditures or plant operating expenses.

We currently own or lease, and have in the past owned or leased, and in the future we may own or lease, properties that have been used over the years for natural gas gathering, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom we 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, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination or to perform remedial operations to prevent future contamination.

We 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. In addition, we are working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. The estimated remediation costs are expected to be approximately $0.3 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

We acquired LIG Pipeline Company, and its subsidiaries, on April 1, 2004 from American Electric Power Company ("AEP"). Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. AEP has indemnified us 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. We do not expect to incur any material liability in connection with the remediation associated with these sites.

We acquired assets from Duke Energy Field Services, L.P. ("DEFS") in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations had been identified at levels that exceeded the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The estimated remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase and sale agreement, DEFS retained the liability for cleanup of the Conroe site. Moreover, DEFS has entered into an agreement with a third-party company pursuant to which the remediation costs associated with the Conroe site have been assumed by this third-party company that specializes in remediation work. We do not expect to incur any material liability in connection with the remediation associated with these sites.

Air Emissions. Our operations are, and our future operations will likely be, subject to the Clean Air Act and comparable state statutes. Amendments to the Clean Air Act were enacted in 1990. Moreover, recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas require or will require most industrial operations in the United States to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies. As a result of these amendments, our processing and fractionating plants, pipelines, and storage facilities or any of our future assets that emit volatile organic compounds or nitrogen oxides may become subject to increasingly stringent regulations, including requirements that some sources install maximum or reasonably available control technology. Such requirements, if applicable to our operations, could cause us to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission related issues. In addition, the 1990 Clean Air Act Amendments established a new operating permit for major sources, which applies to some of the facilities and which may apply to some of our possible future facilities. 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 implementation of the 1990 Clean Air Act Amendments will not have a material adverse effect on our financial condition or operating results.

Clean Water Act. The Federal Water Pollution Control Act, also known as the Clean Water Act, and similar 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. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

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

Safety Regulations. Our 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 TRRC regulates our 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. We believe that our 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 our results of operations or financial positions.

Office Facilities

In addition to our gathering and treating facilities discussed above, we occupy approximately 65,000 square feet of space at our executive offices in Dallas, Texas under a lease expiring in March 2011 and 16,000 square feet of office space for our south Louisiana operations in Houston, Texas with lease terms expiring in January 2013.

Employees

As of December 31, 2005, we had approximately 496 full-time employees. Approximately 218 of our employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. We are not party to any collective bargaining agreements, and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Item 1A. *Risk Factors*

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

Acquisitions typically increase our debt and subject us to other substantial risks, which could adversely affect our results of operations.

Our future financial performance will depend, in part, on our ability to make acquisitions of assets and businesses at attractive prices. From time to time, we will evaluate and seek to acquire assets or businesses that we believe complement our existing business and related assets. We may acquire assets or businesses that we plan to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of 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 our 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 our operations and cash flows. If we consummate any future acquisition, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We continue to consider large acquisition candidates and transactions. The integration, financial and other risks discussed above will be amplified if the size of our future acquisitions increases.

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of gas processing and transportation assets by large industry participants. A material decrease in such divestitures will limit our opportunities for future acquisitions and could adversely affect our growth plans.

We are vulnerable to operational, regulatory and other risks associated with South Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes, because we have a significant portion of our assets located in South Louisiana.

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

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

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

In addition, our operations in South Louisiana are dependent upon continued 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 a adverse effect on our financial condition and results of operations.

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

We are subject to significant risks due to fluctuations in commodity prices. These risks are based upon three components of our business: (1) we purchase certain volumes of natural gas at a price that is a percentage of a relevant index; (2) certain processing contracts for our Gregory system and our Plaquemine and Gibson processing plants expose us to natural gas and NGL commodity price risks; and (3) part of our fees from our Conroe and Seminole gas plants as well as those acquired in the El Paso Acquisition are based on a portion of the NGLs produced, and, therefore, is subject to commodity price risks.

The margins we realize from purchasing and selling a portion of the natural gas that we transport through our pipeline systems decrease in periods of low natural gas prices because our gross margins related to such purchases are based on a percentage of the index price. For the years ended December 31, 2004 and 2005, we purchased approximately 9% and 7.5% respectively, of our gas at a percentage of relevant index. Accordingly, a decline in the price of natural gas could have an adverse impact on our results of operations.

A portion of our profitability is affected by the relationship between natural gas and NGL prices. For a component of our Gregory system and our Plaquemine plant and Gibson plant volumes, we purchase natural gas, process natural gas and extract NGLs, and then sell the processed natural gas and NGLs. A portion of our profits from the plants acquired in the El Paso Acquisition is dependent on NGL prices and elections by us and the producers. In cases where we process gas for producers when they have the ability to decide whether to process their gas, we may elect to receive a processing fee or we may retain and sell the NGLs and keep the producer whole on its sale of natural gas. Since we extract energy content, which we measure in Btus, from the gas stream in the form of the liquids or consume it as fuel during processing, we reduce the Btu content of the natural gas. Accordingly, our margins under these arrangements can be negatively affected in periods in which the value of natural gas is high relative to the value of NGLs.

In the past, the prices of natural gas and NGLs have been extremely volatile and we expect this volatility to continue. For example, in 2004, the NYMEX settlement price for natural gas for the prompt month contract ranged from a high of $7.98 per MMBtu to a low of $5.08 per MMBtu. In 2005, the same index ranged from $13.91 per MMBtu to $6.12 per MMBtu. A composite of the OPIS Mt. Belvieu monthly average liquids price based upon our average liquids composition in 2004 ranged from a high of approximately $0.98 per gallon to a low of approximately $0.66 per gallon. In 2005, the same composite ranged from approximately $1.16 per gallon to approximately $0.80 per gallon.

We may not be successful in balancing our purchases and sales. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

The markets and prices for residue gas and NGLs depend upon factors beyond our control. These factors include 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;
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

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

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

In order to maintain or increase throughput levels in our natural gas gathering systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies. We may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity near our 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. Drilling activity generally decreases as oil and natural gas prices decrease. Tax policy changes could have a negative impact on drilling activity, reducing supplies of natural gas available to our systems. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in natural gas production or in the level of drilling activity in our principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position.

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

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

Growing our business by constructing new pipelines and processing and treating facilities subjects us 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.

One of the ways we intend to grow our business is through the construction of additions to our existing gathering systems and construction of new pipelines and gathering, processing and treating facilities. The construction of pipelines and gathering, processing and treating facilities requires the expenditure of significant amounts of capital, which may exceed our expectations. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, we face the risks of construction delay and additional costs due to obtaining rights-of-way.

We have limited control over the development of certain assets because we are not the operator.

As the owner of non-operating interests in the Seminole and Blue Water gas processing plants, we do not have the right to direct or control the operation of the plants. As a result, the success of the activities conducted at these plants, which are operated by a third party, may be affected by factors outside of our control. The failure of the third-party operator to make decisions, perform its services, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations affecting these plants, including environmental laws and regulations, in a proper manner could result in material adverse consequences to our interest and adversely affect our results of operations.

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

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

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

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations.

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

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other pipelines, and the price of, and demand for, natural gas in the markets we serve.

For the year ended December 31, 2005, approximately 74% of our sales of gas which were transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities 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 us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

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

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

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

Our operations are subject to the many hazards inherent in the gathering, compressing, treating and processing of natural gas and storage of residue gas, 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 our related operations. Our operations are concentrated in Texas, Louisiana and the Mississippi Gulf Coast, and a natural disaster or other hazard affecting this region could have a material adverse effect on our operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. Our business interruption insurance covers only our Gregory processing plant. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

The threat of terrorist attacks has resulted in increased costs, and future war or risk of war may adversely impact our results of operations and our 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. Uncertainty surrounding retaliatory military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, and the possibility that infrastructure facilities, including pipelines, production facilities, and transmission and distribution facilities, could be direct targets, or indirect casualties, of an act of terror. Instability in the financial markets as a result of terrorism, the war in Iraq or future developments could also affect our ability to raise capital.

Changes in the insurance markets attributable to the threat of terrorist attacks have made certain types of insurance more difficult for us to obtain. Our insurance policies now generally exclude acts of terrorism. Such insurance is not available at what we believe to be acceptable pricing levels. A lower level of economic activity could also result in a decline in energy consumption, which could adversely affect our revenues or restrict our future growth.

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

While the Federal Energy Regulatory Commission, or FERC, generally does not regulate any of our operations, directly or indirectly, it influences certain aspects of our business and the market for our products. As a raw natural gas gatherer, we generally are exempt from FERC regulation under the Natural Gas Act of 1938, or NGA, but FERC regulation still significantly affects our business. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Some of our intrastate natural gas transmission pipelines are subject to regulation as a common carrier and as a gas utility by the Texas Railroad Commission, or TRRC. The TRRC’s jurisdiction extends to both rates and pipeline safety. The rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a complaint. Should a complaint be filed or should regulation become more active, our business may be adversely affected.

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

The states in which we conduct operations administer federal pipeline safety standards under the Pipeline Safety Act of 1968. The “rural gathering exemption” under the Natural Gas Pipeline Safety Act of 1968 presently exempts substantial portions of our 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 our natural gas transmission pipelines. In response to recent pipeline accidents in other parts of the country, Congress and the Department of Transportation have passed or are considering heightened pipeline safety requirements.

Compliance with pipeline integrity regulations issued by the TRRC, or those issued by the United States Department of Transportation, or DOT, in December of 2003 could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately $0.3 million for the year ended December 31, 2005 and $1.9 million in 2004 and we expect the costs for compliance with TRRC and DOT regulations to be $2.4 million in the aggregate during 2006 and 2007. If our pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then we may be required to repair or replace sections of such pipelines, the cost of which cannot be estimated at this time.

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

Many of the operations and activities of our gathering systems, plants and other facilities, including the natural gas and processing liquids business in South Louisiana recently acquired from El Paso, are subject to significant federal, state and local environmental laws and regulations. These laws and regulations impose obligations related to air emissions and discharge of pollutants from our facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these 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 through which our gathering systems pass, 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 or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our 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 our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability.

Our use of derivative financial instruments has in the past and could in the future result in financial losses or reduce our income.

We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions, and we use futures and option contracts traded on the New York Mercantile Exchange. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. We could incur financial losses or fail to recognize the full value of a market opportunity as a result of volatility in the market values of the underlying commodities or if one of our counterparties fails to perform under a contract.

Due to our lack of asset diversification, adverse developments in our gathering, transmission, treating, processing and commercial services businesses would materially impact our financial condition.

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

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

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

Item 1B. *Unresolved Staff Comments*

We do not have any unresolved staff comments.

Item 2. *Properties*

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

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipeline was built was purchased in fee. Our processing plants are located on land that we lease or own in fee. Our treating facilities are generally located on sites provided by producers or other parties.

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

Item 3. *Legal Proceedings*

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we may be a defendant in various legal proceedings and litigation arising in the ordinary course of business. These include litigation on disputes related to contracts, property rights, use or damage and personal injury. 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, this insurance may not 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.

Item 4. *Submission of Matters to a Vote of Security Holders*

No matters were submitted to security holders during the fourth quarter of the year ended December 31, 2005.

PART II

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

Our common units are listed on the NASDAQ National Market under the symbol "XTEX". On February 24, 2006, the market price for the common units was $36.65 per unit and there were approximately 11,000 record holders and beneficial owners (held in street name) of our common units and one-record holder of our subordinated units. There is no established public trading market for our subordinated units.

The following table shows the high and low closing sales prices per common unit, as reported by the NASDAQ National Market, for the periods indicated.

	Common Unit Price Range(a)		Cash Distribution Paid per Unit(a)(b)
	High	Low	
2005:			
Quarter Ended December 31	$ 40.25	$ 32.98	$ 0.51
Quarter Ended September 30	44.90	38.51	0.49
Quarter Ended June 30	38.78	32.68	0.47
Quarter Ended March 31	36.70	31.90	0.46
2004:			
Quarter Ended December 31	$ 33.00	$ 29.91	$ 0.45
Quarter Ended September 30	31.65	26.42	0.43
Quarter Ended June 30	29.72	24.38	0.42
Quarter Ended March 31	28.03	20.38	0.40
2003:			
Quarter Ended December 31	$ 21.79	$ 19.28	$ 0.375
Quarter Ended September 30	19.90	16.63	0.350
Quarter Ended June 30	17.20	12.18	0.275
Quarter Ended March 31	12.25	10.74	0.288(c)

(a) Unit prices and cash distributions per unit have been adjusted for the two-for-one unit split on March 29, 2004.

(b) For each quarter, an identical cash distribution was paid on all outstanding subordinated units.

(c) Reflects minimum quarterly distribution of $0.25 for the quarter ended March 31, 2004 and the pro rata portion of the $0.25 minimum quarterly distribution, covering the period for December 17, 2002 closing of our initial public offering through December 31, 2002.

Within 45 days after the end of each quarter, we will distribute all of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. During the subordination period (as described below), the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.25 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. Our available cash consists generally of all cash on hand at the end of the fiscal quarter, less reserves that our general partner determines are necessary to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;

plus all cash on hand for the quarter resulting from working capital borrowings made after the end of the quarter on the date of determination of available cash.

Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Our distributions are effectively made 98 percent to unitholders and two percent to our general partner, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Incentive distributions to our general partner increase to 13 percent, 23 percent and 48 percent based on incremental distribution thresholds as set forth in our partnership agreement.

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

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.25 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

The subordination period will extend until the first day of any quarter beginning after December 31, 2007 in which each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the “adjusted operating surplus” as defined in the partnership agreement generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the 2% general partner interest during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Upon expiration of the subordination period, each outstanding subordinated unit will convert into one common unit and will participate pro rata with the other common units in distributions of available cash.

If the Partnership meets the applicable financial tests in the partnership agreement for the three consecutive four-quarter periods ending on December 31, 2005 or December 31, 2006, up to 4,666,000 of the subordinated units may be converted into common units prior to December 31, 2007. The Partnership met the financial tests for three consecutive four-quarter periods ended December 31, 2005, and as a result 2,333,000 subordinated units converted to common units upon the payment of the fourth quarter distribution on February 15, 2006. If the Partnership meets these tests for the three consecutive four-quarter periods ending on or after December 31, 2006, an additional 2,333,000 of the subordinated units will convert to common units.

Item 6. *Selected Financial Data*

The following table sets forth selected historical financial and operating data of Crosstex Energy, L.P. as of and for the dates and periods indicated. The selected historical financial data are derived from the audited financial statements of Crosstex Energy, L.P. In addition, our summary historical financial and operating data include the results of operations of the Corpus Christi system, the Gregory gathering system and the Gregory processing plant beginning in May 2001, the Vanderbilt system beginning in December 2002, the Mississippi pipeline system and Seminole processing plant beginning in June 2003, the LIG assets beginning in April 2004, and the Graco assets beginning in January 2005, the Cardinal assets beginning in May 2005, and the El Paso South Louisiana processing assets beginning November 1, 2005.

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

	Crosstex Energy, L.P.				
	Year Ended December 31, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001
	(Dollars in thousands, except per unit amounts)				
Statement of Operations Data:					
Revenues:					
Midstream	$ 2,982,874	$ 1,948,021	$ 989,697	$ 437,432	$ 362,673
Treating	48,606	30,755	23,966	14,817	24,353
Profit on energy trading activities	1,568	2,228	2,266	1,791	1,946
Total revenues	3,033,048	1,981,004	1,015,929	454,040	388,972
Operating costs and expenses:					
Midstream purchased gas	2,860,823	1,861,204	946,412	414,244	344,755
Treating purchased gas	9,706	5,274	7,568	5,767	18,078
Operating expenses	56,736	38,340	19,814	11,409	7,761
General and administrative(1)	32,697	20,866	10,067	7,554	5,583
Impairments	—	—	—	4,175	2,873
(Gain) loss on derivatives	9,968	(279)	361	134	5,660
Gain on sale of property	(8,138)	(12)	—	—	—
Depreciation and amortization	36,024	23,034	13,268	7,745	6,101
Total operating costs and expenses	2,997,816	1,948,427	997,490	451,028	390,811
Operating income (loss)	35,232	32,577	18,439	3,012	(1,839)
Other income (expense):					
Interest expense, net	(15,767)	(9,220)	(3,392)	(2,717)	(2,253)
Other income (expense)	392	798	179	49	174
Total other income (expense)	(15,375)	(8,422)	(3,213)	(2,668)	(2,079)
Income before minority interest and taxes	19,857	24,155	15,226	344	(3,918)
Minority interest	(441)	(289)	—	—	—
Federal income taxes	(216)	(162)	—	—	—
Net income (loss)	$ 19,200	$ 23,704	$ 15,226	$ 344	$ (3,918)
Net income per limited partner unit-basic(2)	$ 0.56	$ 0.98	$ 0.89	$ 0.02	N/A
Net income per limited partner unit-diluted(2)	$ 0.51	$ 0.95	$ 0.88	$ 0.02	N/A
Distributions per limited partner unit(3)	$ 1.93	$ 1.70	$ 1.25	$ 0.028	N/A
Balance Sheet Data:					
Working capital surplus (deficit)	$ (11,681)	$ (34,724)	$ (4,572)	$ (10,330)	$ (2,254)
Property and equipment, net	667,142	324,730	203,909	109,948	84,951
Total assets	1,425,158	586,771	366,050	233,185	168,376
Long-term debt	522,650	148,700	60,750	22,550	60,000
Partners' equity	401,285	144,050	154,610	88,158	41,155

	Crosstex Energy, L.P.				
	Year Ended December 31, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001
	(Dollars in thousands, except per unit amounts)				
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 14,009	$ 48,103	$ 46,460	$ (5,672)	$ (10,244)
Investing activities	(615,017)	(124,371)	(110,289)	(33,240)	(52,535)
Financing activities	596,615	81,899	62,687	39,868	44,476
Other Financial Data:					
Midstream gross margin	$ 122,051	$ 86,817	$ 43,285	$ 23,188	$ 17,918
Treating gross margin	38,900	25,481	16,398	9,050	6,275
Total gross margin(4)	$ 160,951	$ 112,298	$ 59,683	$ 32,238	$ 24,193
Operating Data:					
Pipeline throughput (MMBtu/d)	1,302,000	1,289,000	626,000	392,000	313,000
Natural gas processed (MMBtu/d)(5)	1,825,000	425,000	132,000	86,000	61,000
Commercial Services (MMBtu/d)	181,000	210,000	259,000	230,000	283,000

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(1) For the year ended December 31, 2003, the amount for which general partner was entitled to reimbursement from us for allocated general and administrative expenses was limited to $6.0 million. Such limitation did not apply to expenses incurred in connection with acquisitions or business development opportunities evaluated on our behalf. General and administrative expenses in 2003 also include $3.2 million related to stock-based compensation.

(2) Net income (loss) per limited partner unit is not applicable for periods prior to our initial public offering. Net income per unit of $0.02 for the year ended December 31, 2002 represents allocation of our 2002 net income for the period from December 17, 2002 to December 31, 2002.

(3) Distributions include fourth quarter 2005 distributions of $0.51 per unit paid in February 2006 and fourth quarter 2004 distributions of $0.45 per unit paid in February 2005. Distributions in 2003 include fourth quarter 2003 distributions of $0.375 per unit paid in February 2004 and 2002 distributions include fourth quarter 2002 distributions of $0.028 per unit paid in February 2003.

(4) Gross margin is defined as revenue, including treating fee revenues, less related cost of purchased gas.

(5) Processed volumes 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 us.

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

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

Overview

We are a Delaware limited partnership formed by Crosstex Energy, Inc. ("CEI") on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast and in Mississippi and Louisiana. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, while our Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the year ended December 31, 2005, 76% of our gross margin was generated in the Midstream division with the balance in the Treating division. We manage our business by focusing on gross margin because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas or NGLs for a fee. We buy and sell most of our gas at a fixed relationship to the relevant index price so our margins are not significantly affected by changes in gas prices. As explained under “Commodity Price Risk” below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

Since the formation of our predecessor, we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2001 through December 31, 2005, we have invested approximately $973 million to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, and the volumes of natural gas liquids handled at our fractionation facilities. Our treating segment margins are largely a function of the number and size of treating plants in operation and fees earned for removing impurities and from natural gas liquids at a non-operated processing plant. We generate revenues from five primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants and fractionating and marketing the recovered natural gas liquids;
- treating natural gas at our treating plants;
- recovering carbon dioxide and natural gas liquids at a non-operated processing plant; and
- providing off-system marketing services for producers.

The bulk of our operating profits has historically been derived from the margins we realize for gathering and transporting natural gas through our pipeline systems. Generally, we buy gas from a producer, plant, or transporter at either a fixed discount to a market index or a percentage of the market index. We then transport and resell the gas. The resale price is based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. See “Commodity Price Risk” below for a discussion of how we manage our business to reduce the impact of price volatility.

Processing and fractionation revenues are largely fee based. Our processing fees are largely based on either a percentage of the liquids volume recovered, or a fixed fee per unit processed. Fractionation and marketing fees are generally fixed per unit of product.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 51% and 53% of the operating income in our Treating division for the year ended December 31, 2005 and 2004, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 38% and 43% of the operating income in our Treating division for the year ended December 31, 2005 and 2004, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 11% and 4% of the operating income in our Treating division for the year ended December 31, 2005 and 2004, respectively.

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.

Our general and administrative expenses are dictated by the terms of our partnership agreement and our omnibus agreement with Crosstex Energy, Inc. Our general partner and its affiliates are reimbursed for expenses incurred on our behalf. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. For the 12 month period ended in December 2003, the amount which we reimbursed our general partner and its affiliates for costs incurred with respect to the general and administrative services performed on our behalf could not exceed $6.0 million. This reimbursement limitation did not apply to the cost of any third-party legal, accounting or advisory services received, or the direct expenses of management incurred in connection with acquisition or business development opportunities evaluated on our behalf. This limitation expired in December 2003.

Crosstex Energy, Inc. modified certain terms of certain outstanding options in the first quarter of 2003 which allowed the option holders to elect to be paid in cash for the modified options based on the fair value of the options. These modifications resulted in variable award accounting for the modified options until the option holders elected to cash out the options or the election to cash out the options lapsed. Crosstex Energy, Inc. was responsible for paying the intrinsic value of the options for the holders who elected to cash out their options. December 31, 2003 was the last valuation date that a holder of modified options could elect the cash-out alternative. Accordingly, effective January 1, 2004, we ceased applying variable accounting for the remaining modified options. We recognized total compensation expense of approximately $5.3 million related to these modified options, of which $3.2 million has been included in general and administrative expense and $2.1 million has been included in operating expense in the year ended December 31, 2003.

We have grown significantly through asset purchases in recent years, which creates many of the major differences when comparing operating results from one period to another. The most significant asset purchases since January 2003 were the acquisition of the DEFS assets, LIG Pipeline Company and its subsidiaries and the El Paso Corporation processing and liquids business in southern Louisiana. We also purchased treating assets totaling $16.0 million during 2005.

On November 1, 2005 we acquired El Paso Corporation’s processing and liquids business in South Louisiana for $481.0 million. The assets acquired include 2.3 billion cubic feet per day of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The primary facilities and other assets we acquired consist of: (1) the Eunice processing plant and fractionation facility; (2) the Pelican processing plant; (3) the Sabine Pass processing plant; (4) a 23.85% interest in the Blue Water gas processing plant; (5) the Riverside fractionator and loading facility; (6) the Cajun Sibon pipeline and (7) the Napoleonville natural gas liquid storage facility.

On January 2, 2005 we acquired all of the assets of Graco Operations for $9.26 million. Graco’s assets consisted of 26 treating plants and associated inventory. On May 1, 2005 we acquired all of the assets of Cardinal Gas Services for $6.7 million. Cardinal’s assets consisted of nine gas treating plants, 19 operating wellhead gas processing plants for dewpoint suppression, and equipment inventory.

In April 2004 we acquired LIG Pipeline Company and its subsidiaries (collectively, “LIG”) from a subsidiary of American Electric Power Company (“AEP”) for $73.7 million in cash. The principal assets acquired consist of approximately 2,000 miles of gas gathering and transmission systems located in 32 parishes extending from northwest and north-central Louisiana through the center of the state to the south and southeast Louisiana and five processing plants, including three idle plants, that straddle the pipeline in three locations and have a total processing capability of 663,000 MMbtu/d. The system has a throughout capacity of 900,000 MMbtu/d and average throughput at the time of our acquisition was approximately 560,000 MMbtu/d. Customers include power plants, municipal gas systems, and industrial markets located principally in the industrial corridor between New Orleans and Baton Rouge. The LIG system is connected to several interconnected pipelines and the Jefferson Island Storage facility providing access to additional system supply. We subsequently sold one of the idle plants with a capacity of 225,000 MMBtu/d in September 2005 and realized a gain on sale of $8.0 million.

We acquired the Duke Energy Field Services assets, or DEFS assets, in June 2003 for $68.1 million in cash. The principal assets acquired were the Mississippi pipeline system, a 638-mile natural gas gathering and transmission system in south central Mississippi that serves utility and industrial customers, and a 12.4% non-operating interest in the Seminole gas processing plant, which provides carbon dioxide separation and sulfur removal services for several major oil companies in West Texas.

Commodity Price Risk

Our profitability has been and will continue to be affected by volatility in prevailing NGL product and natural gas prices. Changes in the prices of NGL products can correlate closely with changes in the price of crude oil. NGL product and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for crude oil, NGL products, and natural gas.

Profitability under our gas processing contracts is impacted by the margin between NGL sales prices and the cost of natural gas and may be negatively affected by decreases in NGL prices or increases in natural gas prices. Changes in natural gas prices impact our profitability since the purchase price of a portion of the gas we buy is based on a percentage of a particular natural gas price index for a period, while the gas is resold at a fixed dollar relationship to the same index. Therefore, during periods of low gas prices, these contracts can be less profitable than during periods of higher gas prices. However, on most of the gas we buy and sell, margins are not affected by such changes because the gas is bought and sold at a fixed relationship to the relevant index. Therefore, while changes in the price of gas can have very large impacts on revenues and cost of revenues, the changes are equal and offsetting.

Set forth in the table below is the volume of the natural gas purchased and sold at a fixed discount or premium to the index price and at a percentage discount or premium to the index price for our principal gathering and transmission systems and for our producer services business for the year ended December 31, 2005.

	Year Ended December 31, 2005			
	Gas Purchased		Gas Sold	
Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(In thousands of MMBtu's)			
LIG system	119,061	6,442	125,503	—
South Texas system(1)	161,613	21,092	167,252	—
Other assets and activities	101,932	3,533	105,466	—

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(1) Gas sold is less than gas purchased due to production of natural gas liquids on certain assets included in the south Texas system.

We estimate that, due to the gas that we purchase at a percentage of index price, for each $0.50 per MMBtu increase or decrease in the price of natural gas, our gross margins increase or decrease by approximately $1.6 million on an annual basis (before consideration of our hedge positions). As of December 31, 2005, we have hedged approximately 78% of our exposure to such fluctuations in natural gas prices in 2006. We expect to continue to hedge our exposure to gas prices when market opportunities appear attractive.

CELP processes approximately 59% of its volume at Eunice, Pelican, Sabine and Blue Water under "percent of proceeds" contracts, under which we receive as a fee a portion of the liquids produced, and 41% of volume as fixed fee per unit processed. Under percent of proceeds contracts, we are exposed to changes in the prices of natural gas liquids. For the years 2006 and 2007, we have purchased puts or entered into forward sales covering all of our anticipated minimum share of natural gas liquids production.

Our processing plants at Plaquemine and Gibson have a variety of processing contract structures. In general, we buy gas under keep-whole arrangements in which we bear the risk of processing, percentage-of-proceeds arrangements in which we receive a percentage of the value of the liquids recovered, and "theoretical" processing arrangements in which the settlement with the producer is based on an assumed processing result. Because we have the ability to bypass certain volumes when processing is uneconomic, we can limit our exposure to adverse processing margins. During periods when processing margins are favorable, we can substantially increase the volumes we are processing.

For the year ended December 31, 2005, we purchased a small amount (approximately 5.5%) of the natural gas volumes on our Gregory system under contracts in which we were exposed to the risk of loss or gain in processing the natural gas. The remaining approximately 94.5% of the natural gas volumes on our Gregory system were purchased at a spot or market price less a discount that includes a fixed margin for gathering, processing and marketing the natural gas and NGLs at our Gregory processing plant with no risk of loss or gain in processing the natural gas.

We own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon dioxide under a long-term arrangement. Revenues at the plant are derived from a fee it charges producers, including those at the Seminole San Andres unit, for each Mcf of carbon dioxide returned to the producer for reinjection. The fees currently average approximately $0.57 for each Mcf of carbon dioxide returned. Reinjected carbon dioxide is used in a tertiary oil recovery process in the field. The plant also receives 50% of the NGLs produced by the plant. Therefore, we have commodity price exposure due to variances in the prices of NGLs. During 2005, our share of NGLs totaled approximately 5.9 million gallons at an average price of $0.91 per gallon. We have executed forward sales on approximately 80% of our anticipated 2006 share of NGLs.

Gas prices can also affect our profitability indirectly by influencing drilling activity and related opportunities for gas gathering, treating and processing.

Results of Operations

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

	Years Ended December 31,		
	2005	2004	2003
		(Dollars in millions)	
Midstream revenues	$ 2,982.9	$ 1,948.0	$ 989.7
Midstream purchased gas	2,860.8	1,861.2	946.4
Midstream gross margin	122.1	86.8	43.3
Treating revenues	48.6	30.8	24.0
Treating purchased gas	9.7	5.3	7.6
Treating gross margin	38.9	25.5	16.4
Total gross margin	$ 161.0	$ 112.3	$ 59.7
Midstream Volumes (MMBtu/d):			
Gathering and transportation	1,302,000	1,289,000	626,000
Processing	1,825,000	425,000	132,000
Producer services	181,000	210,000	259,000
Treating Plants in Operation at Year-end	112	74	52

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Gross Margin. Midstream gross margin was $122.1 million for the year ended December 31, 2005 compared to $86.8 million for the year ended December 31, 2004 an increase of $35.2 million, or 41%. This increase was primarily due to acquisitions, volatile prices in the last half of the year and operational improvements on existing systems.

The acquisition of El Paso Corporation's natural gas processing and liquids business in south Louisiana contributed $14.1 million of gross margin in the fourth quarter of 2005. The acquisition of the LIG assets on April 1, 2004 contributed $6.3 million to midstream gross margin in 2005 in our first full year of ownership. In addition, the acquisition of all outside interests in Crosstex Pipeline Partners, Ltd. as of December 31, 2004, accounted for a gross margin increase of $1.7 million. Relatively high and volatile natural gas prices during the quarters created favorable margin opportunities on several systems, offset by the negative impact on processing margins of high gas prices, as certain gas was no longer economical to process. The impact of these high and volatile gas prices on midstream operations was a gross margin increase of $5.4 million. During the fourth quarter, declines in gas prices created an imbalance gain of $4.5 million, and made processing more profitable. Operational improvements and volume increases contributed margin growth of $5.1 million on the Vanderbilt, Arkoma, and Denton County systems. In addition, the Gregory Gathering system had a margin increase of $1.7 million primarily due to two measurement disputes which were settled during the year.

Treating gross margin was $38.9 million for the year ended December 31, 2005 compared to $25.5 million in the same period in 2004, an increase of $13.4 million, or 53%. The increase in treating plants in service from 74 plants at December 31, 2004 to 112 plants at December 31, 2005 contributed approximately $7.1 million in gross margin. Existing plant assets contributed $5.0 million in gross margin growth due primarily to plant expansion projects and increased volumes. The acquisition and installation of dew point control plants in 2005 contributed an additional $0.6 million to gross margin.

Profit on Energy Trading Activities. The profit on energy trading activities was $1.6 million for the year ended December 31, 2005 compared to $2.2 million for the year ended December 31, 2004. The decrease in profit on energy trading activities is primarily due to a volume decrease associated with contracts not renewed in 2005. This is an activity that we are is de-emphasizing.

Operating Expenses. Operating expenses were $56.7 million for the year ended December 31, 2005 compared to $38.3 million for the year ended December 31, 2004, an increase of $18.4 million, or 48%. An increase of $5.3 million was associated with the acquisition of the El Paso assets. LIG assets added $4.6 million of the variance due to the fact the assets were a part of our business for the entire year as opposed to nine months in 2004. Midstream operating expenses also increased by $2.6 million due to small acquisitions, expansions of systems and the addition of compressors or other rental services. The growth in treating plants in service due to acquisition of the Graco assets and the Cardinal assets as well as internal growth increased operating expenses by $5.2 million. Operations expense includes stock-based compensation expense of $0.4 million and $0.2 million in 2005 and 2004, respectively.

General and Administrative Expenses. General and administrative expenses were $32.7 million for the year ended December 31, 2005 compared to $20.9 million for the year ended December 31, 2004, an increase of $11.8 million, or 57%. A significant part of the increased expenses was $6.0 million of additional staffing related costs. The staff additions required to manage and optimize our acquisitions account for the majority of the change, although a number of leadership and strategic positions were added that will allow us to absorb future growth more efficiently. Other expenses, including Sarbanes Oxley and other consulting fees, office rent, utilities, and travel expenses, account for $2.6 million of the increase. General and administrative expenses include stock-based compensation expense of $3.7 million and $0.8 million in 2005 and 2004, respectively. This increase in stock-based compensation primarily relates to restricted stock and unit grants and $0.4 million in accelerated options.

(Gain) Loss on Derivatives. We had a loss on derivatives of $10.0 million for the year ended December 31, 2005 compared to a gain on derivatives of $0.3 million for the year ended December 31, 2004. The loss in 2005 includes a $9.2 million loss on puts acquired in the third quarter of 2005 related to the acquisition of the El Paso assets and a loss of $0.8 million associated with derivatives for the third-party on-system financial transactions and storage financial transactions primarily due to higher commodity prices at year end. In August 2005 we acquired put options, or rights to sell a portion of the liquids from the plants at a fixed price over a two-year period beginning January 1, 2006 for a premium of $18.7 million as part of the overall risk management plan related to the acquisition of the El Paso assets which closed on November 1, 2005. In December 2005 we sold a portion of these puts for $4.3 million. We did not designate these put options to obtain hedge accounting treatment as of December 31, 2005 and therefore, these put options did not qualify as hedges as of December 31, 2005 and were marked to market through our consolidated statement of operations. The puts represent options, but not the obligation, to sell the related underlying liquids volumes at a fixed price. As the price of the underlying liquids increased significantly in the period, the value of the puts declined, which is reflected in gain/loss on derivatives.

Gain on Sale of Property. During 2005, the Partnership sold an inactive gas processing facility acquired as part of the LIG acquisition, which accounted for a substantial part of the $8.1 million gain on sale of property.

Depreciation and Amortization. Depreciation and amortization expenses were $36.0 million for the year ended December 31, 2005 compared to $23.0 million for the year ended December 31, 2004, an increase of $13.0 million, or 56%. The acquisitions of the El Paso assets contributed $5.5 million and the LIG assets contributed $1.3 million. New treating plants placed in service and acquired resulted in an increase of $2.3 million. The remaining $3.9 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Dallas office, computer software and equipment, and expansions on midstream assets.

Interest Expense. Interest expense was $15.8 million for the year ended December 31, 2005 compared to $9.2 million for the year ended December 31, 2004, an increase of $6.5 million, or 71%. The increase relates primarily to an increase in average debt outstanding due to borrowings for acquisitions and internal growth projects. Average interest rates also increased from 2004 to 2005 (weighted average rate of 6.3% in 2005 compared to 6.1% in 2004).

Other Income. Other income was $0.4 million for the year ended December 31, 2005 compared to $0.8 million for the year ended December 31, 2004. Other income in 2004 includes $0.3 million related to a reimbursement for a construction project in excess of our costs for such project.

Minority Interest in Subsidiary. We recognized $0.4 million of minority interest expense for the year ended December 31, 2005 compared to $0.3 million for the year ended December 31, 2004 related to the third-party joint venture partner's 50% share of the Crosstex DC Gathering, J.V. We began consolidating this joint venture on January 1, 2004 upon adoption of FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.*

Income Tax Expense. Income tax expense was $0.2 million for the year ended December 31, 2005 and December 31, 2004. The tax expense relates to the Partnership's wholly-owned taxable corporate structure formed in conjunction with the acquisition of the LIG Pipeline Company and its subsidiaries in April 2004.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Gross Margin. Midstream gross margin was $86.8 million for the year ended December 31, 2004 compared to $43.3 million for the year ended December 31, 2003, an increase of $43.5 million, or 101%. This increase was primarily due to the acquisitions of the LIG assets on April 1, 2004 and DEFS assets on June 30, 2003, which added an incremental $27.7 million and $7.9 million, respectively, to midstream gross margin. The volume growth of 956,000 MMBtu/d, or 97%, in gathering, transportation, and processing was primarily due to the acquired LIG and DEFS assets. Also contributing to improved margins were higher processing margins and volumes from existing gas processing operations, which increased margins by $3.4 million from 2004 to 2003.

Treating gross margin was $25.5 million for the year ended December 31, 2004 compared to $16.4 million in the year ended December 31, 2003, an increase of $9.1 million, or 55%. Of this increase, $4.5 million was due to the Seminole Plant, one of the assets acquired from DEFS, being owned for a full year. The Seminole Plant has increased from 20% of operating income in 2003 to 34% of operating income during 2004, as the Seminole Plant was only owned for the last six months of 2003. Also contributing to the significant growth was the placement of an additional 37 plants in service since December 31, 2003, which was offset in part by 15 plant retirements. The net plant additions of 22 generated $4.1 million in additional gross margin.

Operating Expenses. Operating expenses were $38.3 million for the year ended December 31, 2004 compared to $19.8 million for the year ended December 31, 2003, an increase of $18.5 million, or 93%. Increases of $3.5 million and $9.5 million were associated with the acquisition of the DEFS and LIG assets, respectively. General operations expense (expenses not directly related to specific assets) was $6.0 million for 2004 compared to $1.7 million for 2003. The majority of the $4.3 million increase was related to higher technical services support required by the newly-acquired assets and additional expenditures related to our pipeline integrity program. The growth in treating plants in service increased operating expenses by $1.2 million. Stock-based compensation included in operating expense was $0.2 million and $2.1 million for the periods ending December 31, 2004 and

December 31, 2003, respectively. During 2003, certain outstanding CEI options were accounted for using variable accounting due to a “cash-out” modification offered for such options and stock compensation expense was recognized because the estimated fair value of the options increased during 2003. The “cash-out” modification offered during 2003 that caused the variable accounting treatment expired on December 31, 2003 and, effective January 1, 2004, the remaining CEI options are accounted for as fixed options. Stock-based compensation recognized in 2004 represents the amortization of costs associated with awards under long-term incentive plans, including restricted units and option grants with exercise prices below market prices on the grant date.

General and Administrative Expenses. General and administrative expenses were $20.9 million for the year ended December 31, 2004 compared to $10.1 million for the year ended December 31, 2003, an increase of $10.8 million, or 107%. The increase was due in part to the general and administrative expense limit set by our partnership agreement for 2003, which resulted in general and administrative expenses in excess of specified levels being borne by the general partner. Had the limitation not been in place, general and administrative expenses would have been $13.5 million, resulting in an actual increase from 2003 to 2004 of $7.4 million, or 55%. A significant part of the increased expenses was $5.0 million of additional staffing related costs. The staff additions required to manage and optimize our LIG and DEFS acquisitions account for the majority of the change, although a number of leadership and strategic positions were added that will allow us to absorb future growth more efficiently. Consistent with staffing for future growth, an additional $1.0 million in consulting costs were made to upgrade our systems, providing a more scalable infrastructure. Sarbanes Oxley compliance costs were an additional $1.1 million for 2004 compared to zero in 2003. Other expenses, including professional fees, office rent, and travel expenses, account for $1.7 million of the increase. Stock-based compensation included in general and administrative expense was $0.8 million and $3.2 million for the years ending December 31, 2004 and December 31, 2003, respectively. During 2003, certain outstanding CEI options were accounted for using variable accounting due to a “cash-out” modification offered for such options and stock compensation expense was recognized because the estimated fair value of the options increased during 2003. The “cash-out” modification offered during 2003 that caused the variable accounting treatment expired on December 31, 2003 and, effective January 1, 2004, the remaining CEI options are accounted for as fixed options. Stock-based compensation recognized in 2004 represents the amortization of costs associated with awards under long-term incentive plans, including restricted units and option grants with exercise prices below market prices on the grant date.

Depreciation and Amortization. Depreciation and amortization expenses were $23.0 million for the year ended December 31, 2004 compared to $13.3 million for the year ended December 31, 2003, an increase of $9.8 million, or 74%. The increase related to the DEFS assets was $2.6 million and the increase related to the LIG assets was $3.3 million. New treating plants placed in service resulted in an increase of $2.2 million. The remaining $1.7 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Gregory Plant and the consolidation of Denton County assets.

Interest Expense. Interest expense was $9.2 million for the year ended December 31, 2004 compared to $3.4 million for the year ended December 31, 2003, an increase of $5.8 million, or 172%. The increase relates primarily to an increase in average debt outstanding. Average interest rates also increased from 2003 to 2004 (weighted average rate of 6.1% in 2004 compared to 5.4% in 2003).

Other Income. Other income was $0.8 million for the year ended December 31, 2004 compared to $0.2 million for the year ended December 31, 2003. Other income in 2004 includes $0.3 million related to a reimbursement for a construction project in excess of our costs for such projects.

Minority Interest in Subsidiary. We recognized $0.3 million of minority interest expense for the year ended December 31, 2004 related to the third-party joint venture partner’s 50% share of the Crosstex DC Gathering, J.V. We began consolidating this joint venture on January 1, 2004 upon adoption of FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.*

Income Tax Expense. Income tax expense was $0.2 million for the year ended December 31, 2004 compared to $0 for the year ended December 31, 2003, an increase of $0.2 million. The tax expense relates to the Partnership’s wholly-owned taxable corporate structure formed in conjunction with the acquisition of the LIG Pipeline Company and its subsidiaries in April 2004.

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. For further details on our accounting policies and a discussion of new accounting pronouncements, see Note 2 of the Notes to Consolidated Financial Statements.

Revenue Recognition and Commodity Risk Management. We recognize revenue for sales or services at the time the natural gas or natural gas liquids are delivered or at the time the service is performed.

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

In accordance with Statement of Financial Accounting Standards No. 133 (“SFAS No. 133”), *Accounting for Derivative Instruments and Hedging Activities*, all derivatives and hedging instruments are recognized as assets or liabilities at fair value. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

We conduct “off-system” gas marketing operations as a service to producers on systems that we do not own. We refer to these activities as part of Commercial Services. In some cases, we earn an agency fee from the producer for arranging the marketing of the producer’s natural gas. In other cases, we purchase the natural gas from the producer and enter into a sales contract with another party to sell the natural gas.

We manage price risk related to future physical purchase or sale commitments for Commercial Services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance future commitments and significantly reduce risk related to the movement in natural gas prices. However, we are subject to counter-party risk for both the physical and financial contracts. Prior to October 26, 2002, we accounted for our Commercial Services natural gas marketing activities as energy trading contracts in accordance with EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* EITF 98-10 required energy-trading contracts to be recorded at fair value with changes in fair value reported in earnings. In October 2002, the EITF reached a consensus to rescind EITF No. 98-10. Accordingly, energy trading contracts entered into subsequent to October 25, 2002, should be accounted for under accrual accounting rather than mark-to-market accounting unless the contracts meet the requirements of a derivative under SFAS No. 133. Our energy trading contracts qualify as derivatives, and accordingly we continue to use mark-to-market accounting for both physical and financial contracts of the Commercial Services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to Commercial Services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period, in addition to the net realized gains or losses on settled contracts, is reported net as profit or loss on energy trading activities in the statements of operations.

Impairment of Long-Lived Assets. In accordance with Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we evaluate the long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management’s judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management’s estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas 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;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas exploration and production activities will not occur or be successful;
- our 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 our cash flows, which could require us to record an impairment of an asset.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $14.0 million for the year ended December 31, 2005 compared to cash provided by operations of $48.1 million for the year ended December 31, 2004. Income before non-cash income and expenses was $62.8 million in 2005 and $48.3 million in 2004. Changes in working capital used $48.7 million in cash flows from operating activities in 2005 and used $0.2 million in cash flows from operating activities in 2004. Income before non-cash income and expenses increased between years primarily due to asset acquisitions as discussed in “Results of Operations — Year Ended December 31, 2005 compared to year ended December 31, 2004.” Changes in working capital are primarily due to the timing of collections at the end of the quarterly periods. We collect and pay large receivables and payables at the end of each calendar month and the timing of these payments and receipts may vary by a day or two between month-end periods, causing these fluctuations. Increased natural gas and natural gas liquids prices together with the acquisition of the El Paso assets contributed to increases in accounts receivable, accrued gas sales, accounts payable, accrued gas purchases, imbalance receivables and payables and inventory costs during 2005.

Net cash used in investing activities was $615.0 million and $124.4 million for the year ended December 31, 2005 and 2004, respectively. Net cash used in investing activities during 2005 primarily related to the El Paso assets ($489.4 million), the Graco assets ($9.3 million), and the Cardinal assets ($6.7 million). The remaining cash used in investing activities for 2005 relates to internal growth projects including expenditures of approximately $80.0 million for the North Texas Pipeline (“NTPL”) project, $21.2 million for buying, refurbishing and installing treating plants and $19.9 million for expansions, well connections and other capital projects on the pipeline, gathering and processing assets. Net cash used in investing activities during 2004 related to the LIG acquisition ($73.7 million) and the purchase of the outside partner interests in Crosstex Pipeline Partners ($5.1 million) as well as internal growth projects. The primary internal growth projects during 2004 were buying, refurbishing and installing treating plants ($24.5 million).

Net cash provided by financing activities was $596.6 million and $81.9 million for the years ended December 31, 2005 and 2004, respectively. Financing activities in 2005 relate to proceeds from the sale of common units and subordinated units discussed below and increased borrowings under our bank credit facility and senior secured notes. Financing activities for 2005 relate primarily to funding the acquisitions of the El Paso assets, Graco assets, Cardinal assets, and to funding the NTPL project. Financing activities for 2004 relate primarily to funding the LIG acquisition. Distributions to partners totaled $43.3 million in 2005 compared to distributions of $34.3 million in 2004 due to increases in the distribution levels to the limited partners between years and due to increases in the incentive distribution to the general partners. Drafts payable decreased by $8.8 million requiring the use of cash in 2005 compared to an increase in drafts payable of $28.2 million providing cash from financing activities in 2004. In order to reduce our interest costs, we borrow money to fund outstanding checks as 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.

Working Capital Deficit. We had a working capital deficit of $11.7 million as of December 31, 2005, primarily due to drafts payable of $29.9 million as of the same date. As discussed under “Cash Flows” above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank. We borrow money under our $750.0 million credit facility to fund checks as they are presented. As of December 31, 2005, we had approximately $343.0 million of available borrowing capacity under this facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2005 and 2004.

June 2005 Sale of Senior Subordinated Units. In June 2005, we issued 1,495,410 senior subordinated units in a private offering for net proceeds of $51.1 million, including our general partner’s $1.1 million capital contribution. The senior subordinated units were issued at $33.44 per unit, which represents a discount of 13.7% to the market value of common units on such date, and automatically converted to common units on a one-for-one basis on February 24, 2006. The senior subordinated units were not entitled to distributions of available cash until they converted to common units.

November 2005 Sale of Senior Subordinated B Units. On November 1, 2005, we issued 2,850,165 Senior Subordinated Series B Units in a private placement for a purchase price of $36.84 per unit. We received net proceeds of approximately $107.1 million, including our general partner’s $2.1 million capital contribution and net of expenses associated with the sale. The Senior Subordinated Series B Units automatically converted into common units on November 14, 2005 at a ratio of one common unit for each Senior Subordinated Series B Units and were not entitled to distributions paid on November 14, 2005.

November 2005 Public Offering. In November and December 2005, we issued 3,731,050 common units to the public at a purchase price of $33.25 per unit. The offering resulted in net proceeds to us of approximately $120.9 million, including the general partner’s $2.5 million capital contribution and net of expenses associated with the offering.

Senior Secured Notes. In November 2005, we completed a private placement of $85 million of senior secured notes pursuant to our master shelf agreement with an institutional lender with an interest rate of 6.23% and a maturity of ten years.

Capital Requirements. The natural gas gathering, transmission, treating and processing businesses are capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to be:

- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain existing operating capacity of our assets and to extend their useful lives, or other capital expenditures which do not increase the partnership’s cash flows; and
- growth capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity, processing plants or treating plants, and to construct or acquire new pipelines, processing plants or treating plants, and expenditures made in support of that growth.

Given our objective of growth through acquisitions and large capital expansions, we anticipate that we will continue to invest significant amounts of capital to grow and to build and acquire assets. We actively consider a variety of assets for potential development or acquisition.

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.51 per quarter and to fund a portion of our anticipated capital expenditures through December 31, 2006.

Total capital expenditures are budgeted to be approximately $120 million in 2006. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below and with future issuances of units. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2005, is as follows:

	Payments Due by Period						
	Total	2006	2007	2008 (In millions)	2009	2010	Thereafter
Long-Term Debt	$ 522.6	$ 6.5	$ 10.0	$ 9.4	$ 9.4	$ 342.3	$ 145.0
Capital Lease Obligations	—	—	—	—	—	—	—
Operating Leases	94.1	14.6	14.4	14.1	13.8	13.5	23.7
Unconditional Purchase Obligations	14.1	14.1	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—	—
Total Contractual Obligations	$ 630.8	$ 35.2	$ 24.4	$ 23.5	$ 23.2	$ 355.8	$ 168.7

The above table does not include any physical or financial contract purchase commitments for natural gas.

The unconditional purchase obligations for 2005 primarily relate to the purchase of pipe for the construction of the North Texas Pipeline and for gas turbine gearbox and controls required for the south Louisiana assets.

Description of Indebtedness

As of December 31, 2005 and 2004, long-term debt consisted of the following (dollars in thousands):

	December 31, 2005	December 31, 2004
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2005 and 2004 were 6.69% and 4.99%, respectively	$ 322,000	$ 33,000
Senior secured notes, weighted average interest rate of 6.64% and 6.95%, respectively	200,000	115,000
Note payable to Florida Gas Transmission Company	650	700
	522,650	148,700
Less current portion	(6,521)	(50)
Debt classified as long-term	$ 516,129	$ 148,650

On March 31, 2005, we amended the bank credit facility, increasing availability under the facility to $250 million, eliminating the distinction between an acquisition and working capital facility and extending the maturity date from June 2006 to March 2010. On November 1, 2005, we amended our bank credit facility to, among other things, provide for revolving credit borrowings up to a maximum principal amount of $750 million and the issuance of letters of credit in the aggregate face amount of up to $300 million, which letters of credit reduce the credit available for revolving credit borrowings. The bank credit agreement includes procedures for additional financial institutions selected by us to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by us and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders. The maturity was also extended to November 2010.

The credit facility was used for the El Paso acquisition and will be used to finance the acquisition and development of gas gathering, treating, and processing facilities, as well as general partnership purposes. At December 31, 2005, $407.0 million was outstanding under the credit facility, including $85.0 million of letters of credit, leaving approximately $343.0 available for future borrowings. The credit facility will mature in November 2010, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the credit facility may be re-borrowed.

The obligations under the bank credit facility are secured by first priority liens on all of our material pipeline, gas gathering, treating, and processing assets, all material working capital assets and a pledge of all of our equity interests in certain of our subsidiaries, and rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by certain of our subsidiaries. We may prepay all loans under the bank credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

Indebtedness under the credit facility bears interest at our option at the administrative agent's reference rate plus 0.0% to 0.50% or LIBOR plus 1.00% to 2.00%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.00% to 2.00% per annum, plus a fronting fee of 0.125% per annum. We incur quarterly commitment fees based on the unused amount of the credit facilities.

The credit agreement prohibits us from declaring distributions to unitholders if any event of default, as defined in the credit agreement, exists or would result from the declaration of distributions. In addition, the bank credit facility contains various covenants that, among other restrictions, limit our ability and the ability of our subsidiaries to:

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make distributions;
- change the nature of our business;
- enter into certain commodity contracts;
- make certain amendments to our or the Operating Partnership's partnership agreement; and
- engage in transactions with affiliates.

The credit facility also adjusted financial covenants requiring us to maintain:

- a maximum ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of (i) 5.25 to 1.00 for any fiscal quarter ending during the period commencing on the effective date of the credit facility and ending March 31, 2006, (ii) 4.75 to 1.00 for any fiscal quarter ending during the period commencing on April 1, 2006, and (iii) 4.00 to 1.00 for any fiscal quarter ending thereafter, pro forma for any asset acquisitions (but during an acquisition adjustment period (as defined in the credit agreement), the maximum ratio is increased to 4.75 to 1); and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, equal to 3.0 to 1.0.

Each of the following will be an event of default under the bank credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;
- certain judgments against us or any of our subsidiaries, in excess of certain allowances;
- certain ERISA events involving us or our subsidiaries;

- cross defaults to certain material indebtedness;
- certain bankruptcy or insolvency events involving us or our subsidiaries;
- a change in control (as defined in the credit agreement); and
- the failure of any representation or warranty to be materially true and correct when made.

Senior Secured Notes. In June 2003, we entered into a master shelf agreement with an institutional lender pursuant to which it issued $30.0 million aggregate principal amount of senior secured notes with an interest rate of 6.95% and a maturity of seven years. In July 2003, we issued $10.0 million aggregate principal amount of senior secured notes pursuant to the master shelf agreement with an interest rate of 6.88% and a maturity of seven years. In June 2004, the master shelf agreement was amended, increasing the amount issuable under the agreement from $50.0 million to $125.0 million. In June 2004, we issued $75.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years. In June 2005, the master shelf agreement was amended, increasing the amount issuable under the agreement from $125.0 million to $200.0 million. In November 2005, we issued $85.0 million aggregate principal amount of senior secured notes with an interest rate of 6.23% and a maturity of ten years.

The notes represent our senior secured obligations and rank at least *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with our obligations under the credit facility, by first priority liens on all of our material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in certain of our subsidiaries. The senior secured notes are guaranteed by our significant subsidiaries.

The initial $40.0 million of senior secured notes are redeemable, at our option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the master shelf agreement. The $75.0 million senior secured notes issued in June 2004 and the $85.0 million issued in November 2005 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance.

The master shelf agreement relating to the notes contains substantially the same covenants and events of default as the bank credit facility.

If an event of default resulting from bankruptcy or other insolvency events occurs, the senior secured notes will become immediately due and payable. If any other event of default occurs and is continuing, holders of more than 50.1% in principal amount of the outstanding notes may at any time declare all the notes then outstanding to be immediately due and payable. If an event of default relating to nonpayment of principal, make-whole amounts or interest occurs, any holder of outstanding notes affected by such event of default may declare all the notes held by such holder to be immediately due and payable.

We were in compliance with all debt covenants at December 31, 2005 and 2004 and expect to be in compliance for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement in June 2003, the lenders under the bank credit facility and the initial purchasers of the senior secured notes entered into an Intercreditor and Collateral Agency Agreement, which was acknowledged and agreed to by our operating partnership and its subsidiaries. As amended in 2005, this agreement appoints Bank of America to act as collateral agent and authorized the bank to execute various security documents on behalf of the lenders under the bank credit facility and the initial purchases of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing Crosstex Energy Services, L.P.’s obligations under the bank credit facility and the master shelf agreement.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2003, 2004 or 2005. Although the impact of inflation has not been significant 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 and Other Contingencies

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

Recent Accounting Pronouncements

In March 2005, the FASB issued Interpretation No. 47, *“Accounting for Conditional Asset Retirement Obligations”* (FIN 47). FIN 47 clarifies that the term “conditional asset retirement obligation” as used in FASB Statement No. 143, *“Accounting for Asset Retirement Obligations”* 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, FIN 47 provides that a liability for the fair value of a conditional asset retirement obligation should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB Statement No. 143. FIN 47 is effective at December 31, 2005. At December 31, 2005, the Partnership cannot estimate the timing and/or method of settlement for substantially all their assets where a legal obligation to perform an asset retirement activity exists and therefore adoption of FIN 47 had no impact on our financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123R *“Share-Based Payment,”* which requires compensation related to all stock-based awards, including stock options be recognized in the consolidated financial statements. The provisions of SFAS No. 123R are effective for the first annual reporting period that begins after June 15, 2005. We will adopt this standard on January 1, 2006 and will elect the modified-prospective transition method. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption should be measured and accounted for in accordance with SFAS No. 123R. The unvested portion of awards that are granted prior to the effective date will be accounted for in accordance with SFAS No. 123. We expect that stock option grants will continue to be a significant part of employee compensation, and therefore, SFAS No. 123R will have a significant impact on our financial statements. We do not expect SFAS No. 123R to significantly change recorded compensation expense related to grants of restricted Partnership units and restricted CEI shares. Had we adopted SFAS No. 123R in prior periods, we believe the impact of that standard would have approximated the impact of SFAS No. 123 as described in the *“Stock Based Employee Compensation”* disclosure of pro forma net income and earnings per share. As of December 31, 2005, we had 0.7 million unit options and 50,000 CEI stock options outstanding that had not yet vested, with a remaining estimated fair value of $2.3 million and we had 0.2 million unvested restricted units and 0.2 million unvested restricted CEI shares with a remaining estimated fair value of $12.7 million. Based on these estimated fair values, we currently anticipate stock based compensation expense for 2006 will be $5.7 million.

In May 2005, the FASB issued SFAS No. 154, *“Accounting Changes and Error Corrections”* (SFAS 154), which replaces Accounting Principles Board Opinion No. 20 *“Accounting Changes”* and FASB Statement No. 3, *“Reporting Accounting Changes in Interim Financial Statements.”* SFAS 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005, and requires retrospective application to prior period financial statements of voluntary changes in accounting principle, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. The consolidated financial position, results of operations or cash flows will only be impacted by SFAS 154 if we implement a voluntary change in accounting principle or corrects accounting errors in future periods.

Disclosure Regarding Forward-Looking Statements

This report on Form 10-K includes "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. Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "forecast," "may," "believe," ''will," ''expect," "anticipate," "estimate," ''continue" or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. We have identified factors that could cause actual plans or results to differ materially from those included in any forward-looking statements. These factors include those described in "Item 1A. Risk Factors", or in our other Securities and Exchange Commission filings, among others. Such risks and uncertainties are beyond our ability to control, and in many cases, we cannot predict the risks and uncertainties that could cause our actual results to differ materially from those indicated by the forward-looking statements. You should consider these risks when you are evaluating us.

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.

Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

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

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

Interest Rate Risk

We are exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At December 31, 2005, our variable rate debt had a carrying value of 322.7 million, which approximated its fair value, and our fixed rate debt had a carrying value of $200.0 million and an approximate fair value of $203.9 million. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk. This is accomplished through a mix of bank debt with short-term variable rates and fixed rate senior and subordinated debt.

The following table shows the carrying amount and fair value of long-term debt and the hypothetical change in fair value that would result from a 100-basis point change in interest rates. Unless otherwise noted, the hypothetical change in fair value could be a gain or a loss depending on whether interest rates increase or decrease.

(in millions)	Carrying Amount	Fair Value *(a)*	Hypothetical Change in Fair Value
December 31, 2005			
Long-term debt	($ 522.7)	($ 529.8)	$ 7.1
December 31, 2004			
Long-term debt	($ 148.7)	($ 157.5)	$ 8.8

(a) Fair value is based upon current market quotes and is the estimated amount required to purchase our long-term debt on the open market. This estimated value does not include any redemption premium.

Commodity price risk. Approximately 7.5% of the natural gas we purchase for resale is purchased on a percentage of the relevant natural gas price index, as opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. We have hedged approximately 80% of our exposure to gas price fluctuations through the end of 2006.

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

We have commodity price risk associated with our processed volumes of natural gas. We currently process gas under four main types of contractual arrangements:

1. *Keep-whole contracts:* Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost (“shrink”) in processing. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. We control our risk on our current keep-whole contracts primarily through our ability to bypass processing when it is not profitable for us.

2. *Percent of proceeds contracts:* Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of proceeds contracts, but decline during periods of low NGL prices.

3. *Theoretical processing contracts:* Under these contracts, we stipulate with the producer the assumptions under which we will assume processing economics for settlement purposes, independent of actual processing results or whether the stream was actually processed. These contracts tend to have an inverse result to the keep-whole contracts, with better margins as processing economics worsen.

4. *Fee based contracts:* Under these contracts we have no commodity price exposure, and are paid a fixed fee per unit of volume that is treated or conditioned.

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

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

We manage our price risk related to future physical purchase or sale commitments for our producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas prices. However, we are subject to counterparty credit risk for both the physical and financial contracts. We account for certain of our producer services natural gas marketing activities as energy trading contracts or derivatives. These energy-trading contracts are recorded at fair value with changes in fair value reported in earnings. Accordingly, any gain or loss arising from changes to the fair market value of the derivative and physical delivery contract related to our producer services natural gas marketing activities are recognized in earnings as profit or loss from energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period is reported as profit or loss on energy trading contracts in the statement of operations. In addition, realized gains and losses from settled contracts accounted for as cash flow hedges are also recorded in profit or loss on energy trading contracts. As of December 31, 2005, outstanding natural gas swap agreements, natural gas liquids swap agreements, swing swap agreements, storage swap agreements and other derivative instruments had a net fair value liability of $3.7 million, excluding the fair value asset of $5.1 million associated with the natural gas liquids puts. The aggregate effect of a hypothetical 10% increase in gas and natural gas liquids prices would result in an increase of approximately $12.5 million in the net fair value liability of these contracts as of December 31, 2005. The value of the natural gas puts would also decrease as a result of an increase in natural gas liquids prices but we are unable to determine the impact of a 10% price change. Our maximum loss on these puts is the remaining $5.1 million cost for the puts.

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

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-38 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 the Chief Executive Officer and Chief Financial Officer of Crosstex Energy, GP, LLC, of the design and operating effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2005 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission. Because of inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our partnership have been detected.

(b) *Changes in Internal control over financial reporting*

There has been no change in our internal controls over financial reporting that occurred in the three months ended December 31, 2005 that has materially affected, or is reasonably likely to materially affect, our internal controls 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 and Executive Officers of the Registrant*

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

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

The following table shows information for the directors and executive officers of Crosstex Energy GP, LLC. Executive officers and directors serve until their successors are duly appointed or elected.

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis***	44	President, Chief Executive Officer and Director
James R. Wales	52	Executive Vice President — Commercial
A. Chris Aulds	44	Executive Vice President — Public and Governmental Affairs
Jack M. Lafield	55	Executive Vice President — Corporate Development
William W. Davis***	52	Executive Vice President and Chief Financial Officer
Joe A. Davis***	45	Executive Vice President, General Counsel and Secretary
Robert S. Purgason	49	Senior Vice President-Treating Division
Danny L. Thompson	56	Senior Vice President — Engineering and Operations
Rhys J. Best**	59	Director and Member of the Conflicts Committee* and Compensation Committee
Frank M. Burke**	66	Director and Member of the Audit Committee*
James C. Crain**	57	Director and Member of the Conflicts Committee
C. Roland Haden**	65	Director and Member of the Audit Committee
Bryan H. Lawrence	63	Chairman of the Board
Sheldon B. Lubar**	76	Director and Member of the Compensation Committee*
Cecil E. Martin**	64	Director and Member of the Audit Committee
Robert F. Murchison**	52	Director and Member of the Compensation Committee

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* Denotes chairman of committee.

** Denotes independent director.

*** Executive Officer not related to other Executive Officers with the same last name.

Barry E. Davis, President, Chief Executive Officer and Director, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of our predecessor. Mr. Davis 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, Inc. Mr. Davis holds a B.B.A. in Finance from Texas Christian University.

James R. Wales, Executive Vice President — Commercial, joined our predecessor in December 1996. As one of the founders of Sunrise Energy Services, Inc., he helped build Sunrise into a major national independent natural gas marketing company, with sales and service volumes in excess of 600,000 MMBtu/d. Mr. Wales started his career as an engineer with Union Carbide. In 1981, he joined Producers Gas Company, a subsidiary of Lear Petroleum Corp., and served as manager of its Mid-Continent office. In 1986, he joined Sunrise as Executive Vice President of Supply, Marketing and Transportation. From 1993 to 1994, Mr. Wales was the Chief Operating Officer of Triumph Natural Gas, Inc., a private midstream business. Prior to joining Crosstex, Mr. Wales was Vice President for Teco Gas Marketing Company. Mr. Wales holds a B.S. degree in Civil Engineering from the University of Michigan, and a Law degree from South Texas College of Law.

A. Chris Aulds, Executive Vice President — Public and Governmental Affairs, together with Barry E. Davis, participated in the management buyout of Comstock Natural Gas in December 1996. Mr. Aulds joined Comstock Natural Gas, Inc. in October 1994 as a result of the acquisition by Comstock of the assets and operations of Victoria Gas Corporation. Mr. Aulds joined Victoria in 1990 as Vice President responsible for gas supply, marketing and new business development and was directly involved in the providing of risk management services to gas producers. Prior to joining Victoria, Mr. Aulds was employed by Mobil Oil Corporation as a production engineer before being transferred to Mobil's gas marketing division in 1989. There he assisted in the creation and implementation of Mobil's third-party gas supply business segment. Mr. Aulds holds a B.S. degree in Petroleum Engineering from Texas Tech University.

Jack M. Lafield, Executive Vice President — Corporate Development, joined our predecessor in August 2000. For five years prior to joining Crosstex, Mr. Lafield was Managing Director of Avia Energy, an energy consulting group, and was involved in all phases of acquiring, building, owning and operating midstream assets and natural gas reserves. He also provided project development and consulting in domestic and international energy projects to major industry and financing organizations, including development, engineering, financing, implementation and operations. Prior to consulting, Mr. Lafield held positions of President and Chief Executive Officer of Triumph Natural Gas, Inc., a private midstream business he founded, President and Chief Operating Officer of Nagasco, Inc. (a joint venture with Apache Corporation), President of Producers' Gas Company, and Senior Vice President of Lear Petroleum Corp. Mr. Lafield holds a B.S. degree in Chemical Engineering from Texas A&M University, and is a graduate of the Executive Program at Stanford University.

William W. Davis, Executive Vice President and Chief Financial Officer, joined our predecessor in September 2001, and has over 25 years of finance and accounting experience. Prior to joining our 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. Mr. Davis began his legal career with the Dallas firm of Worsham Forsythe, which merged with the international law firm of Hunton & Williams in 2002. Most recently, he served as a partner in the firm's Energy Practice Group, and served on the firm's Executive Committee. Mr. Davis specialized in facility development, sales, acquisitions and financing for the energy industry, representing entrepreneurial start up/development companies, growth companies, large public corporations and large electric and gas utilities. He received his J.D. from Baylor Law School in Waco and his B.S. degree from the University of Texas in Dallas.

Robert S. Purgason, Senior Vice President — Treating Division, joined Crosstex in October 2004 to lead the Treating Division. Prior to joining Crosstex, Mr. Purgason spent 19 years with Williams Companies in various senior business development and operational roles. He was most recently Vice President of the Gulf Coast Region Midstream Business Unit. Mr. Purgason began his career at Perry Gas Companies in Odessa working in all facets of the treating business. Mr. Purgason received a B.S. degree in Chemical Engineering with honors from the University of Oklahoma.

Danny L. Thompson, Senior Vice President — Engineering and Operations, has held various leadership positions within the midstream energy industry. From March 2005 until August 2005 when he became an employee of Crosstex, he worked with Crosstex as a consultant. Prior to joining Crosstex, he worked for Cantera Natural Gas L.L.C. as vice president, operations and engineering and CMS Field Services as director of engineering and operations. Mr. Thompson holds a bachelor's degree in chemical engineering from Texas A&I University in Kingsville, and he is a registered professional engineer in Texas.

Rhys J. Best joined Crosstex Energy GP, LLC as a director in June 2004. Mr. Best is Chairman and Chief Executive Officer of Lone Star Technologies, Inc., a holding company whose principal operating companies produce and market premium casing, tubing, line pipe and couplings for the oil and gas industry; specialty tubing for the industrial, automotive, and power generation industries; and flat rolled steel and other tubular products and services. Mr. Best has held the position of Chief Executive Officer since June 1998 and he assumed the additional responsibilities of Chairman in January 1999. He began his career at Lone Star as the President and Chief Executive Officer of Lone Star Steel Company, a position he held for eight years before becoming President and Chief Operating Officer of the parent company in 1997. Mr. Best graduated from the University of North Texas with a Bachelor of Business degree and later earned a Masters of Business Administration Degree at Southern Methodist University.

Frank M. Burke joined Crosstex Energy GP, LLC as a director in August 2003. Mr. Burke has served as Chairman, Chief Executive Officer and Managing General Partner of Burke, Mayborn Company Ltd., a private investment company located in Dallas, Texas, since 1984. Prior to that, Mr. Burke was a partner in Peat, Marwick, Mitchell & Co. (now KPMG). He is a member of the National Petroleum Council and also serves as a director of Arch Coal, Inc. and Xanser Corporation. Mr. Burke has also served as a director of Crosstex Energy, Inc. since January 2004. Mr. Burke received his Bachelor of Business Administration and Master of Business Administration from Texas Tech University and his Juris Doctor from Southern Methodist University. He is a Certified Public Accountant and member of the State Bar of Texas.

James C. Crain joined us as a director in December 2005. Since 1989, Mr. Crain has served as president of Marsh Operating Company, an investment management company focusing on energy investing, and since 1997 as general partner of Valmora Partners, L.P., a private investment partnership. Mr. Crain also serves as a director of GeoMet, Inc., a coal-bed methane exploration and production company. Prior to Marsh, he served as a partner at Jenkens & Gilchrist where he headed the law firm's energy section. He graduated from the University of Texas at Austin with a B.B.A. degree, a master of professional accounting and a doctor of jurisprudence. Mr. Crain also serves on the board for the Texas State Historical Association.

C. Roland Haden joined us as a director upon the completion of our initial public offering in December 2002. Mr. Haden held the positions of Vice Chancellor of the Texas A&M System, Director of the Texas Engineering Experiment Station and Dean of Look College of Engineering at Texas A&M University from 1993 to 2002. Prior to joining Texas A&M University, Mr. Haden served as Vice Chancellor for Academic Affairs and Provost of Louisiana State University from 1991 to 1993 and held various positions with Arizona State University, including Dean and Professor of Engineering & Applied Sciences from 1989 to 1991, Provost, ASU West Campus from 1988 to 1989, Vice President for Academic Affairs from 1987 to 1988 and Dean and Professor of Engineering and Applied Sciences from 1978 to 1987. Mr. Haden formerly served as a director of Square D Company, a Fortune 500 electrical manufacturing company, as a director of E-Systems, a Fortune 500 defense contractor, as a member of the Telecommunications Advisory Board of A.T. Kearney, a nationally ranked consulting firm, and as a director of Inter-tel, Inc., a leading telecommunications company. Mr. Haden has also served as a director of Crosstex Energy, Inc. since January 2005. Mr. Haden holds a bachelor's degree from the University of Texas, Arlington, a Masters degree from the California Institute of Technology, and a Ph.D. from the University of Texas, Austin, all in electrical engineering.

Bryan H. Lawrence, Chairman of the Board, joined us as a director upon the completion of our initial public offering in December 2002. Mr. Lawrence is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships, which make investments in companies engaged in the energy industry. The Yorktown partnerships were formerly affiliated with the investment firm of Dillon, Read & Co. Inc., where Mr. Lawrence had been employed since 1966, serving as a Managing Director until the merger of Dillon Read with SBC Warburg in September 1997. Mr. Lawrence also serves as a director of D&K Healthcare Resources, Inc., Hallador Petroleum Company and TransMontaigne Inc., (each a United States publicly traded company) and WinStar Resources, Ltd. (a Canadian public company) and certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests including PetroSantander Inc., Savoy Energy, L.P., Camden Resources, Inc., ESI Energy Services Inc., Ellora Energy Inc., Dernick Resources Inc., Peak Oil & Gas Inc., Cinco Resources Inc., Compass Petroleum Ltd., Momentum Energy Group Inc., Nytis Exploration (USA) Inc. and Kestrel Energy Partners LLC. Mr. Lawrence also serves as a director of Crosstex Energy, Inc. Mr. Lawrence is a graduate of Hamilton College and also has an M.B.A. from Columbia University.

Sheldon B. Lubar joined us as a director upon the completion of our initial public offering in December 2002. Mr. Lubar has been Chairman of the Board of Lubar & Co. Incorporated, a private investment and venture capital firm he founded, since 1977. He was Chairman of the Board of Christiana Companies, Inc., a logistics and manufacturing company, from 1987 until its merger with Weatherford International in 1995. Mr. Lubar has also been a Director of Grant Prideco, Inc., an energy services company, since 2000, and Weatherford International, Inc., an energy services company, since 1995. Mr. Lubar has also served as a director of Crosstex Energy, Inc. since January 2004. Mr. Lubar holds a bachelor's degree in Business Administration and a Law degree from the University of Wisconsin — Madison. He was awarded an honorary Doctor of Commercial Science degree from the University of Wisconsin — Milwaukee.

Cecil E. Martin, Jr., joined us as a director in January 2006. He has been an independent residential and commercial real estate investor since 1991. From 1973 to 1991 he served as chairman of the public accounting firm Martin, Dolan and Holton in Richmond, Virginia. He began his career as an auditor at Ernst and Ernst. He holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant. Mr. Martin also serves on the boards and as chairman of the audit committees for both Comstock Resources, Inc., a growing independent energy company engaged in oil and gas acquisitions, exploration and development, and Bois d'Arc Energy, headquartered in Houston. Mr. Martin also has served as a director of Crosstex Energy, Inc. since January 2006.

Robert F. Murchison joined us as a director upon the completion of our initial public offering in December 2002. Mr. Murchison has been the President of the general partner of Murchison Capital Partners, L.P., a private equity investment partnership since 1992. Prior to founding Murchison Capital Partners, L.P., Mr. Murchison held various positions with Romacorp, Inc., the franchisor and operator of Tony Roma's restaurants, including Chief Executive Officer from 1984 to 1986 and Chairman of the board of directors from 1984 to 1993. He served as a director of Cenergy Corporation, an oil and gas exploration and production company, from 1984 to 1987, Conquest Exploration Company from 1987 to 1991 and has served as a director of TNW Corporation, a short line railroad holding company, since 1981, and Tecon Corporation, a holding company with holdings in real estate development, rail car repair and the fund of funds management business, since 1978. Mr. Murchison has also served as a director of Crosstex Energy, Inc. since January 2004. Mr. Murchison holds a bachelor's degree in history from Yale University.

"Independent" Directors

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

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

Board Committees

The board of directors of Crosstex Energy GP, LLC, has, and appoints the members of, standing Audit, Compensation and Conflicts Committees. Each member of the Audit, Compensation and Conflicts Committees is an independent director in accordance with NASDAQ standards described above. Each of the board committees has a written charter approved by the board. Copies of the charters will be provided to any person, without charge, upon request. Contact Denise LeFevre at 214-721-9245 to request a copy of a charter or send your request to Crosstex Energy, L.P., Attn: Denise LeFevre, 2501 Cedar Springs, Suite 100, Dallas, Texas 75201.

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

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

The Compensation Committee, comprised of Messrs. Lubar (chair), Murchison, and Best, oversees compensation decisions for the officers of the General Partner as well as the compensation plans described herein.

Code of Ethics

Crosstex Energy GP, LLC, has adopted a Code of Business Conduct and Ethics applicable to all of our employees, officers, and directors, with regard to partnership-related activities. The Code of Business Conduct and Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. A copy of our Code of Business Conduct and Ethics will be provided to any person, without charge, upon request. Contact Denise LeFevre at 214-721-9245 to request a copy of the Code or send your request to Crosstex Energy, L.P., Attn: Denise LeFevre, 2501 Cedar Springs, Suite 100, Dallas, Texas 75201. If any substantive amendments are made to the Code of Business Conduct and Ethics or if we or Crosstex Energy GP, LLC grant any waiver, including any implicit waiver, from a provision of the Code to any of our general partner’s executive officers and directors, we will disclose the nature of such amendment or waiver in a report on Form 8-K.

Section 16(a) — Beneficial Ownership Reporting Compliance

Based upon our records, we believe that during 2006 all reporting persons complied with the Section 16(a) filing requirements applicable to them.

Reimbursement of Expenses of our General Partner and its Affiliates

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

Item 11. *Executive Compensation*

The following table sets forth certain compensation information for our chief executive officer and the four other most highly compensated executive officers in 2003, 2004 and 2005. We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation allocable to us. The named executive officers have also received certain equity-based awards from our general partner's general partner.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation Awards(1)		
Name and Principal Position	**Year**	**Salary ($)**	**Bonus ($)**	**Other Annual Compensation ($)**	**Restricted Stock Awards ($)**	**Restricted Unit Awards ($)**	**All Other Compensation ($)**
Barry E. Davis	2005	$300,000	$360,000	—	$656,300	$443,181	—
President and Chief	2004	267,483	247,500	—	291,000	—	—
Executive Officer	2003	210,000	177,000	—	—	285,670	—
James R. Wales	2005	$230,000	$172,500	—	$335,435	$226,502	—
Executive Vice	2004	202,731	126,000	—	363,750	—	—
President	2003	180,000	108,000	—	—	181,790	—
A. Chris Aulds	2005	$230,000	$172,500	—	$335,435	$226,502	—
Executive Vice	2004	200,500	126,000	—	363,750	—	—
President	2003	180,000	108,000	—	—	181,790	—
Jack M. Lafield	2005	$230,000	$217,500	—	$894,400	$955,532	—
Executive Vice	2004	199,436	126,000	—	436,500	—	—
President	2003	170,000	108,000	—	—	181,790	—
William W. Davis	2005	$230,000	$217,500	—	$894,400	$955,532	—
Executive Vice	2004	199,436	126,000	—	436,500	—	—
President and Chief	2003	170,000	108,000	—	—	181,790	—
Financial Officer							

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(1) Executive officers received equity-based awards from our general partner in 2003 and 2005 and from Crosstex Energy, Inc. in 2004 and 2005. For a description of awards granted to date under the Long-Term Incentive Plan. See "— Long-Term Incentive Plan."

Employment Agreements

The executive officers, including Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield and William W. Davis, have entered into employment agreements with the Partnership. The following is a summary of the material provisions of those employment agreements. All of these employment agreements are substantially similar, with certain exceptions as set forth below.

Each of the employment agreements has a term of one year that will automatically be extended such that the remaining term of the agreements will not be less than one year. The employment agreements provide for a base annual salary of $390,000, $275,000, $275,000, $275,000 and $275,000 for Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield and William W. Davis, respectively, as of January 1, 2006.

Except in the event of our becoming bankrupt or ceasing operations, termination for cause or termination by the employee other than for good reason, the employment agreements provide for continued salary payments, bonus and benefits following termination of employment for the remainder of the employment term under the agreement. If a change in control occurs during the term of an employee's employment and either party to the agreement terminates the employee's employment as a result thereof, the employee will be entitled to receive salary payments, bonus and benefits following termination of employment for the remainder of the employment term under the agreement.

The employment agreements also provide for a noncompetition period that will continue until the later of one year after the termination of the employee's employment or the date on which the employee is no longer entitled to receive payments under the employment agreement. During the noncompetition period, the employees are generally prohibited from engaging in any business that competes with us or our affiliates in areas in which we conduct business as of the date of termination and from soliciting or inducing any of our employees to terminate their employment with us or accept employment with anyone else or interfere in a similar manner with our business.

Long-Term Incentive Plan

Crosstex Energy GP, LLC has adopted a long-term incentive plan for employees and directors of Crosstex Energy GP, LLC and its affiliates who perform services for us. The long-term incentive plan, as amended, permits the grant of awards covering an aggregate of 2,600,000 common units, which may be awarded in the form of restricted units or unit options. The plan is administered by the Compensation Committee of Crosstex Energy GP, LLC's board of directors.

Crosstex Energy GP, LLC's board of directors in its discretion may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made. Crosstex Energy GP, LLC's board of directors also has the right to alter or amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of units that may be granted subject to the approval requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

Restricted Units. A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. In the future, the Compensation Committee may make grants under the plan to employees and directors containing such terms as it shall determine under the plan. The Committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted units will vest upon a change of control of us or of our general partner. Under current policy, if a grantee's employment terminates for any reason other than death, disability or retirement, the grantee's restricted units will automatically be forfeited unless, and to the extent, the Compensation Committee provides otherwise. Common units to be delivered upon the vesting of restricted units may be common units acquired by Crosstex Energy GP, LLC in the open market, common units already owned by Crosstex Energy GP, LLC, common units acquired by Crosstex Energy GP, LLC directly from us or any other person or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units which entitles the grantee to distributions attributable to the restricted units prior to vesting of such units.

We intend the issuance of the common units upon vesting of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under current policy, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

Unit Options. The long-term incentive plan currently permits the grant of options covering common units. While unit options may have an exercise price that is less than the fair market value of the units on the date of grant, under current policy it is contemplated that all unit option grants will be equal to or more than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the Compensation Committee. In addition, the unit options will become exercisable upon a change in control of us or our general partner or upon the achievement of specified financial objectives.

Upon exercise of a unit option, Crosstex Energy GP, LLC will acquire common units in the open market or directly from us or any other person or use common units already owned, or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the difference between the cost incurred by it in acquiring these common units and the proceeds received by it from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and Crosstex Energy GP, LLC will pay us the proceeds it received from the optionee upon exercise of the unit option. The unit option plan has been designed to furnish additional compensation to employees and directors and to align their economic interests with those of common unitholders.

Option Grants

No options were granted to the named executive officers in 2005.

Option Exercises and Year-End Option Values

The following table provides information about the number of units issued upon option exercises by the named executive officers during 2005, and the value realized by the named executive officers. The table also provides information about the number and value of options that were held by the named executive officers at December 31, 2005.

Aggregated Option Exercise in Last Fiscal Year and Fiscal Year End Option Values

Name	Units Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options at 12/31/05 (#)		Value of Unexercised In-the-Money Options at 12/31/05 ($)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Barry E. Davis	—	—	60,000	—	$ 1,444,800	—
James R. Wales	—	—	40,000	—	$ 963,200	—
A. Chris Aulds	—	—	40,000	—	$ 963,200	—
Jack M. Lafield	—	—	35,000	—	$ 842,800	—
William W. Davis	35,000	$ 850,150	—	—	—	—

The closing price for the common units was $34.08 at December 31, 2005.

Compensation of Directors

Each director of Crosstex Energy GP, LLC who is not an employee of Crosstex Energy GP, LLC (except Mr. Lawrence) is paid an annual retainer fee of $25,000. Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting, but are paid $750 for each additional meeting that they attend. Also, an attendance fee of $1,000 is paid to each director for each committee meeting he attends, except the Audit Committee members who receive $1,500 for each Audit Committee meeting. Each committee chairman receives $2,500 annually, except for the Audit Committee chairman who receives $7,500 annually. Directors are also reimbursed for related out-of-pocket expenses. Barry E. Davis, as an executive officer of Crosstex Energy GP, LLC, is otherwise compensated for his services and therefore receives no separate compensation for his service as a director.

Compensation Committee Interlocks and Insider Participation

The Compensation Committee of the board of directors of Crosstex Energy GP, LLC determines compensation of the executive officers. Sheldon B. Lubar, Robert F. Murchison, and Rhys J. Best serve as members of the committee, and none of them was an officer or employee of our company or any of our subsidiaries. In addition, none of the executive officers of Crosstex Energy GP, LLC served on the board of directors or on the compensation committee of any other entity for which any executive officers of such other entity served either on the board of directors or Compensation Committee of Crosstex Energy GP, LLC.

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

The following table shows the beneficial ownership of units of Crosstex Energy, L.P. as of February 24, 2006, held by:

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

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

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Crosstex Holdings, L.P.	2,999,000	15.33%	7,001,000	100.0%	37.65%
Kayne Anderson Capital Advisors, L.P.(2)	3,314,591	16.94%	—	—	12.48%
Tortoise Capital Advisors, LLC(3)	1,592,335	8.14%	—	—	5.99%
Barry E. Davis(4)	30,370	*	—	—	*
James R. Wales(4)	21,166	*	—	—	*
A. Chris Aulds(4)	21,113	*	—	—	*
Jack M. Lafield(4)	18,641	*	—	—	*
William W. Davis(4)	16,000	*	—	—	*
Rhys J. Best	6,000	*	—	—	*
Frank M. Burke(4)(5)	16,333	*	—	—	*
James A. Crain	—	—	—	—	—
C. Roland Haden(4)(6)	27,150	*	—	—	*
Bryan H. Lawrence(4)(7)	—	—	—	—	—
Sheldon B. Lubar(4)(8)	29,822	*	—	—	*
Cecil E. Martin	—	—	—		—
Robert F. Murchison(4)(9)	79,822	*	—	—	*
All directors and executive officers as a group (15 persons)	267,417	*	—	—	*

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* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022; Kayne Anderson Capital Advisors, L.P., which is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067; and Tortoise Capital Advisors LLC, which is 10801 Martin Blvd., Ste 222, Overland Park, Kansas 66210.

(2) As reported on a Schedule 13G (Amendment No. 4) filed by Kayne Anderson Capital Advisors, L.P. with the SEC on February 9, 2006 in a joint filing with Richard A. Kayne. Kayne Anderson Capital Advisors, L.P. reports that it has shared voting and investment power with Richard A. Kayne with respect to all 3,314,591 units.

(3) As reported on a Schedule 13G filed by Tortoise Capital Advisors LLC with the SEC on January 10, 2006 in a joint filing with Tortoise Energy Capital Corporation. Tortoise Capital Advisors LLC reports that it has shared voting and investment power with respect to all such units. Tortoise Energy Capital Corporation reports that it has shared voting and investment power with respect to 1,269,913 of these units.

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

(5) Ownership percentage for Mr. Burke includes 13,333 common units issuable pursuant to options which are presently exercisable or exercisable within 60 days of February 24, 2006.

(6) 5,000 units are held in a trust for the benefit of the Mr. Haden's children. Mr. Haden and his spouse are trustees of the trust.

(7) Bryan H. Lawrence is a member and a manager of the general partner of both Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. Both of these limited partnerships own an interest in Crosstex Energy, Inc. as indicated in the following table.

(8) Sheldon B. Lubar is a general partner of Lubar Nominees, and Lubar Nominees holds an ownership interest in Crosstex Energy, Inc. as indicated in the following table.

(9) 50,000 units are held by Murchison Capital Partners, L.P. Mr. Murchison is the President of the Murchison Management Corp., which serves as the general partner of Murchison Capital Partners, L.P. Mr. Murchison and Murchison Capital Partners, L.P. hold ownership interests in Crosstex Energy, Inc. as indicated in the following table.

The following table shows the beneficial ownership of Crosstex Energy, Inc. as of February 24, 2006, held by:

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

In computing the number of shares beneficially owned by a person and the percentage ownership of that person, shares of Common Stock subject to options, if any, held by that person that were exercisable on February 24, 2006 or would be exercisable within 60 days following February 24, 2006 are considered outstanding. However, such shares are not considered outstanding for the purpose of computing the percentage ownership of any other person. To our knowledge and unless otherwise indicated, each stockholder has sole voting and investment power over the shares listed as beneficially owned by such stockholder, subject to community property laws where applicable. Percentage of ownership is based on 12,763,469 shares of Common Stock outstanding as of February 24, 2006.

Name of Beneficial Owner(1)	Shares of Common Stock	Percent
Yorktown Energy Partners IV, L.P.(2)	2,327,098	18.23%
Yorktown Energy Partners V, L.P.(3)	619,320	4.85%
Lubar Nominees(4)	697,498	5.46%
Barry E. Davis	568,772	4.46%
James R. Wales	256,199	2.01%
A. Chris Aulds	318,712	2.50%
Jack M. Lafield	49,495	*
William W. Davis	42,818	*
Frank M. Burke	5,000	*
C. Roland Haden	2,500	*
Bryan H. Lawrence(5)	333,610	2.61%
Sheldon B. Lubar(4)	5,129	*
Cecil E. Martin	—	—
Robert F. Murchison(6)	45,811	*
All directors and executive officers as a group (13 persons)	1,628,246	12.76%

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* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Mr. Lawrence, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P., which is 410 Park Avenue, New York, New York 10022.

(2) As reported on a Form 4 filed with the SEC on November 10, 2005 by Yorktown Energy Partners IV, L.P.

(3) As reported on a Form 4 filed with the SEC on November 10, 2005 by Yorktown Energy Partners V, L.P.

(4) Sheldon B. Lubar is a general partner of Lubar Nominees, and may be deemed to beneficially own the shares held by Lubar Nominees.

(5) Bryan H. Lawrence is a member and a manager of the general partner of both Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P.

(6) 42,500 shares are held by Murchison Capital Partners, L.P. Mr. Murchison is the President of the Murchison Management Corp., which serves as the general partner of Murchison Capital Partners, L.P.

Beneficial Ownership of General Partner Interest

Crosstex Energy GP, L.P. owns all of our 2% general partner interest and all of our incentive distribution rights. Crosstex Energy GP, L.P. is owned 0.001% by its general partner, Crosstex Energy GP, LLC and 99.999%; by its sole limited partner, Crosstex Holdings, L.P.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a)	Weighted-Average Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity Compensation Plans Approved By Security Holders	N/A	N/A	N/A
Equity Compensation Plans Not Approved By Security Holders	1,438,680(1)	$ 18.88(2)	1,161,320

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(1) Our general partner has adopted and maintains a Long Term Incentive Plan for our officers, employees and directors. See Item 11. "Executive Compensation — Long-Term Incentive Plan." The plan, as amended, provides for issuance of a total of 2,600,000 common unit options and restricted units.

(2) The strike prices for outstanding options under the plan as of December 31, 2005 range from $10.00 to $37.00 per unit.

Item 13. *Certain Relationships and Related Transactions*

Our General Partner

Our operations and activities are managed by, and our officers are employed by, the Operating Partnership. Our general partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf. For the twelve months ended December 31, 2003, the amount which we reimbursed the general partner and its affiliates for costs incurred with respect to the general and administrative services performed on our behalf could not exceed $6.0 million. This reimbursement limitation did not apply to the cost of any third-party legal, accounting or advisory services received, or the direct expenses of management incurred, in connection with acquisition or business development opportunities evaluated on behalf of the Partnership.

Our general partner owns a 2% general partner interest in us and all of our incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit.

Relationship with Crosstex Energy, Inc.

General. Crosstex Energy, Inc. indirectly owns 2,999,000 common units and 7,001,000 subordinated units representing approximately 38% limited partnership interest in us. Our general partner owns a 2% general partner interest in us and the incentive distribution rights. Our general partner's ability, as general partner, to manage and operate Crosstex Energy, L.P. and Crosstex Energy, Inc.'s ownership in us effectively gives our general partner the ability to veto some of our actions and to control our management.

Omnibus Agreement. Concurrent with the closing of our initial public offering, we entered into an agreement with Crosstex Energy, Inc., Crosstex Energy GP, LLC and our general partner which governs potential competition among us and the other parties to the agreement. Crosstex Energy, Inc. agreed, and caused its controlled affiliates to agree, for so long as management, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. and its affiliates, or any combination thereof, control our general partner, not to engage in the business of gathering, transmitting, treating, processing, storing and marketing of natural gas and the transportation, fractionation, storing and marketing of NGLs unless it first offers us the opportunity to engage in this activity or acquire this business, and the board of directors of Crosstex Energy GP, LLC, with the concurrence of its conflicts committee, elects to cause us not to pursue such opportunity or acquisition. In addition, Crosstex Energy, Inc. has the ability to purchase a business that has a competing natural gas gathering, transmitting, treating, processing and commercial services business if the competing business does not represent the majority in value of the business to be acquired and Crosstex Energy, Inc. offers us the opportunity to purchase the competing operations following their acquisition. The noncompetition restrictions in the omnibus agreement do not apply to the assets retained and business conducted by Crosstex Energy, Inc. at the closing of our initial public offering. Except as provided above, Crosstex Energy, Inc. and its controlled affiliates are not prohibited from engaging in activities in which they compete directly with us. In addition, Yorktown Energy Partners IV, L.P., Yorktown Energy Partners V, L.P. and any affiliated Yorktown funds are not prohibited from owning or engaging in businesses which compete with us.

Related Party Transactions

Camden Resources, Inc. We treat gas for, and purchase gas from, Camden Resources, Inc. Yorktown Energy Partners IV, L.P. has made equity investments in both Camden and Crosstex Energy, Inc. The gas treating and gas purchase agreements we have entered into with Camden are standard industry agreements containing terms substantially similar to those contained in our agreements with other third parties. During the year ended December 31, 2005, we purchased natural gas from Camden Resources, Inc. in the amount of approximately $67.2 million and received approximately $2.6 million in treating fees from Camden Resources, Inc.

Crosstex Pipeline Partners, L.P. Prior to December 31, 2004, we indirectly owned general and limited partner interests in Crosstex Pipeline Partners, L.P. (CPP) that represented a 28% economic interest. On December 31, 2004, we acquired all of the other limited and general partner interests (approximately 72%) of this partnership for $5.1 million. Purchased assets includes current assets of $1.8 million offset by current liabilities assumed of $1.6 million and property, plant and equipment of approximately $5.0 million. This acquisition makes us the sole limited partner of CPP and Crosstex Pipeline, LLC (a 100% owned subsidiary of ours) the sole general partner. We have entered into various transactions with CPP, and we believe that the terms of these transactions are comparable to those that we could have negotiated with unrelated third parties.

Crosstex Denton County Gathering J.V. We own a 50% interest in Crosstex Denton County Gathering, J.V. (CDC). CDC was formed to build, own and operate a natural gas gathering system in Denton County, Texas. We manage the business affairs of CDC. The other 50% joint venture partner (the CDC Partner) is an unrelated third party who owns and operates the natural gas field in Denton County. In connection with the formation of CDC, we 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%. CDC makes payments directly to us attributable to CDC Partner's 50% share of distributable cash flow to repay the loan. Any balance remaining on the note is due in August 2007.

Lone Star Steel Company. In connection with the completion of our North Texas Pipeline project, during fiscal year 2005 we purchased approximately $0.4 million of steel from Lone Star Steel Company, a subsidiary of Lone Star Technologies, Inc. Rhys J. Best, a director of Crosstex Energy GP, LLC, is the Chairman and Chief Executive Officer of Lone Star Technologies, Inc. We believe that the terms of the transactions with Lone Star are comparable to those that we could have negotiated with other third parties.

Item 14. *Principal Accounting Fees and Services*

The Audit Committee of the board of directors of Crosstex Energy GP, LLC has selected KPMG LLP (KPMG) to continue as our independent auditors for the fiscal year ending December 31, 2006.

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for each of the fiscal years ended December 31, 2005 and December 31, 2004, review of our internal control procedures for the fiscal year ended December 31, 2005 and December 31, 2004, and the reviews of the financial statements included in our Quarterly Reports on Forms 10-Q or services that are normally provided by KPMG in connection with statutory or regulatory filings or engagement for each of those fiscal years, were $1.2 million and $0.9 million, respectively. These amounts also included fees associated with comfort letters and consents related to debt and equity offerings.

Audit-Related Fees

KPMG did not perform any assurance and related services related to the performance of the audit or review of our financial statements for the fiscal years ended December 31, 2005 and December 31, 2004 that were not included in the audit fees listed above.

Tax Fees

We did not incur any fees by KPMG for tax compliance, tax advice and tax planning for the year ended December 31, 2005. During the year ended December 31, 2004 we incurred $0.1 million related to reviews of tax returns, tax consulting and planning.

All Other Fees

KPMG did not render services to us, other than those services covered in the sections captioned “Audit Fees” and “Tax Fees” for the fiscal years ended December 31, 2005 and December 31, 2004.

Audit Committee Approval of Audit and Non-Audit Services

All non-audit services and any services that exceed the annual limits set forth in the policy must be pre-approved by the Audit Committee. In 2006, the Audit Committee has not pre-approved the use of KPMG for any non-audit related services. The Chairman of the Audit Committee is authorized by the Audit Committee to pre-approve additional KPMG audit and non-audit services between Audit Committee meetings; provided that the additional services do not affect KPMG’s independence under applicable Securities and Exchange Commission rules and any such pre-approval is reported to the Audit Committee at its next meeting.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) Financial Statements and Schedules

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

(2) See Schedule II — Valuation and Qualifying Accounts on Page F-36.

(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
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Fourth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of November 1, 2005 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	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 our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate on Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-106927).
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.7 to Amendment No. 1 to our Registration Statement on Form S-3, file No. 333-128282).
4.2	—	Registration Rights Agreement, dated as of November 1, 2005, by and among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Tortoise Energy Capital Corp., Tortoise Energy Infrastructure Corporation and Fiduciary/Claymore MLP Opportunity Fund (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
4.3	—	Registration Rights Agreement, dated as of June 24, 2005, among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Tortoise Energy Capital Corporation and Tortoise Energy Infrastructure Corporation (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 24, 2005, filed with the Commission on June 4, 2005).
10.1	—	Fourth Amended and Restated Credit Agreement, dated as of November 1, 2005, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.2	—	Amended and Restated $125,000,000 Senior Secured Notes Master Shelf Agreement, dated as of March 31, 2005, among Crosstex Energy, L.P., Crosstex Energy Services, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 31, 2005, filed with the Commission on April 6, 2005).
10.3	—	Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated as of June 22, 2005, among Crosstex Energy, L.P., Crosstex Energy Services, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 27, 2005, filed with the Commission on June 28, 2005).
10.4	—	Letter Amendment No. 2 to Amended and Restated Master Shelf Agreement, dated as of November 1, 2005, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.5	—	Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).

Number		Description
10.6	—	First Amendment to Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 1, 2004).
10.7	—	Second Amendment to Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.3 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.8†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan, dated July 12, 2002 (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2002).
10.9†	—	Amendment to Crosstex Energy GP, LLC Long Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.10	—	Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.11†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.12	—	Seminole Gas Processing Plant Gaines County, Texas Joint Operating Agreement dated January 1, 1993 (incorporated by reference to Exhibit 10.10 to our Registration Statement on Form S-1, file No. 333-106927).
10.13	—	Senior Subordinated Unit Purchase Agreement, by and among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Tortoise Energy Capital Corporation and Tortoise Energy Infrastructure Corporation (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 24, 2005, filed with the Commission on June 24, 2005).
10.14	—	Senior Subordinated Series B Unit Purchase Agreement, dated as of October 18, 2005, by and among Crosstex Energy, L.P., and the purchasers named thereon (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 18, 2005, filed with the Commission on October 19, 2005).
10.15	—	Purchase and Sale Agreement, dated as of August 8, 2005, by and between Crosstex Energy, L.P. and El Paso Corporation (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 8, 2005, filed with the Commission on August 11, 2005).
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.

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* Filed herewith.

† As required by Item 14(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 14th day of March 2006.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, L.P., its general partner

By: Crosstex Energy GP, LLC, its general partner

By: /s/ BARRY E. DAVIS
Barry E. Davis,
President and Chief Executive Officer

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

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Director (Principal Executive Officer)	March 13, 2006
/s/ RHYS J. BEST Rhys J. Best	Director	March 13, 2006
/s/ FRANK M. BURKE Frank M. Burke	Director	March 13, 2006
/s/ JAMES C. CRAIN James C. Crain	Director	March 13, 2006
/s/ C. ROLAND HADEN C. Roland Haden	Director	March 13, 2006
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Chairman of the Board	March 13, 2006
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	March 13, 2006
/s/ CECIL E. MARTIN Cecil E. Martin	Director	March 13, 2006
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	March 13, 2006
/s/ WILLIAM W. DAVIS William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 13, 2006

INDEX TO FINANCIAL STATEMENTS

Crosstex Energy, L.P. Financial Statements:

Financial Statement Schedule:

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

In connection with the preparation of the Partnership's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2005, the Partnership's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The Partnership acquired CFS Louisiana Midstream Company and El Paso Dauphin Island Company, L.L.C. during 2005, and management excluded from its assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2005 any internal control evaluation over financial reporting associated with total assets of $488.2 million and total revenues of $66.3 million included in the consolidated financial statements of Crosstex Energy, L.P. and subsidiaries as of and for the year ended December 31, 2005.

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

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005. 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 Partnership'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, L.P. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, 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 effectiveness of Crosstex Energy, L.P.'s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 13, 2006, expressed an unqualified opinion on management's assessment of, and the effective operations of, internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
March 13, 2006

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Crosstex Energy, L.P. (a Delaware limited partnership) maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and 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, management's assessment that Crosstex Energy, L.P. maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations (COSO).

The Partnership acquired CFS Louisiana Midstream Company and El Paso Dauphin Island Company, L.L.C. during 2005, and management excluded from its assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2005 any internal control evaluation over financial reporting associated with CFS Louisiana Midstream Company and El Paso Dauphin Island Company, L.L.C.'s total assets of $488.2 million and total revenues of $66.3 million included in the consolidated financial statements of Crosstex Energy, L.P. and subsidiaries as of and for the year ended December 31, 2005. Our audit of internal control over financial reporting of Crosstex Energy, L.P. also excluded an evaluation of the internal control over financial reporting of CFS Louisiana Midstream Company and El Paso Dauphin Island Company, L.L.C.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2005 and 2004 and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, and our report dated March 13, 2006 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
March 13, 2006

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets
December 31, 2005 and 2004

	2005	2004
	(In thousands except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,405	$ 5,797
Accounts receivable:		
Trade, net of allowance for bad debts of $260 and $60, respectively	60,009	19,453
Accrued revenues	368,860	211,700
Imbalances	7,833	573
Affiliated companies	173	486
Note receivable	845	570
Other	4,896	1,481
Fair value of derivative assets	12,205	3,025
Natural gas and natural gas liquids storage, prepaid expenses, and other	23,549	5,077
Total current assets	479,775	248,162
Property and equipment:		
Transmission assets	194,235	181,679
Gathering systems	36,653	35,624
Gas plants	389,083	125,559
Other property and equipment	26,283	8,952
Construction in process	98,093	18,006
Total property and equipment	744,347	369,820
Accumulated depreciation	(77,205)	(45,090)
Total property and equipment, net	667,142	324,730
Fair value of derivative assets	7,633	166
Intangible assets, net of accumulated amortization of $7,674 and $3,301, respectively	255,197	5,155
Goodwill	6,568	4,873
Other assets, net	8,843	3,685
Total assets	$ 1,425,158	$ 586,771
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 29,855	$ 38,667
Accounts payable	16,567	3,996
Accrued gas purchases	360,458	213,037
Accrued imbalances payable	30,515	2,046
Fair value of derivative liabilities	14,782	2,085
Current portion of long-term debt	6,521	50
Other current liabilities	32,758	23,005
Total current liabilities	491,456	282,886
Long-term debt	516,129	148,650
Deferred tax liability	8,437	8,005
Minority interest	4,274	3,046
Fair value of derivative liabilities	3,577	134
Partners' equity:		
Common unitholders (15,465,528 and 8,755,000 units issued and outstanding at December 31, 2005 and 2004, respectively)	326,617	111,960
Subordinated unitholders (9,334,000 units issued and outstanding at December 31, 2005 and 2004)	16,462	28,002
Senior subordinated unitholders (1,495,410 units issued and outstanding at December 31, 2005)	49,921	—
General partner interest (2% interest with 536,631 and 369,000 equivalent units outstanding at December 31, 2005 and 2004, respectively)	11,522	4,078
Accumulated other comprehensive income (loss)	(3,237)	10
Total partners' equity	401,285	144,050
Total liabilities and partners' equity	$ 1,425,158	$ 586,771

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Years Ended December 31, 2005	2004	2003
	(In thousands except per unit data)		
Revenues:			
Midstream	$ 2,982,874	$ 1,948,021	$ 989,697
Treating	48,606	30,755	23,966
Profit on energy trading activities	1,568	2,228	2,266
Total revenues	3,033,048	1,981,004	1,015,929
Operating costs and expenses:			
Midstream purchased gas	2,860,823	1,861,204	946,412
Treating purchased gas	9,706	5,274	7,568
Operating expenses	56,736	38,340	19,814
General and administrative	32,697	20,866	10,067
(Gain) loss on derivatives	9,968	(279)	361
Gain on sale of property	(8,138)	(12)	—
Depreciation and amortization	36,024	23,034	13,268
Total operating costs and expenses	2,997,816	1,948,427	997,490
Operating income	35,232	32,577	18,439
Other income (expense):			
Interest expense, net of interest income	(15,767)	(9,220)	(3,392)
Other income	392	798	179
Total other income (expense)	(15,375)	(8,422)	(3,213)
Income before minority interest and taxes	19,857	24,155	15,226
Minority interest in subsidiary	(441)	(289)	—
Income tax provision	(216)	(162)	—
Net income	$ 19,200	$ 23,704	$ 15,226
General partner interest in net income	$ 8,652	$ 5,913	$ 1,240
Limited partners' interest in net income	$ 10,548	$ 17,791	$ 13,986
Net income per limited partners' unit:			
Basic	$ 0.56	$ 0.98	$ 0.89
Diluted	$ 0.51	$ 0.95	$ 0.88
Weighted average limited partners' units outstanding:			
Basic	19,006	18,081	15,752
Diluted	20,527	18,633	15,960

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Years ended December 31, 2005, 2004 and 2003

	Common Units	Subordinated Units	Senior Subordinated Units	General Partner Interest	Accumulated Other Comprehensive Income	Total
			(In thousands)			
Balance, December 31, 2002	$ 57,561	$ 30,790	—	$ 983	$ (1,176)	$ 88,158
Net proceeds from issuance of common units	57,336	—	—	—	—	57,336
Capital contributions	—	—	—	1,266	—	1,266
Stock-based compensation	2,121	3,117	—	107	—	5,345
Distributions	(6,016)	(8,522)	—	(742)	—	(15,280)
Net income	5,778	8,208	—	1,240	—	15,226
Hedging gains or losses reclassified to earnings	—	—	—	—	4,267	4,267
Adjustment in fair value of derivatives	—	—	—	—	(1,708)	(1,708)
Balance, December 31, 2003	116,780	33,593	—	2,854	1,383	154,610
Proceeds from exercise of common unit options	425	—	—	—	—	425
Stock-based compensation	367	391	—	243	—	1,001
Distributions	(14,217)	(15,168)	—	(4,932)	—	(34,317)
Net income	8,605	9,186	—	5,913	—	23,704
Hedging gains or losses reclassified to earnings	—	—	—	—	(4,015)	(4,015)
Adjustment in fair value of derivatives	—	—	—	—	2,642	2,642
Balance, December 31, 2004	111,960	28,002	—	4,078	10	144,050
Net proceeds from issuance of common units(1)	223,340	—	—	—	—	223,340
Net proceeds from issuance of senior subordinated units	—	—	49,921	—	—	49,921
Proceeds from exercise of common unit options	1,345	—	—	—	—	1,345
Capital contributions	—	—	—	6,311	—	6,311
Stock-based compensation	1,798	—	—	1,874	—	3,672
Distributions	(16,459)	(17,455)	—	(9,393)	—	(43,307)
Net income	4,633	5,915	—	8,652	—	19,200
Hedging gains or losses reclassified to earnings	—	—	—	—	7,864	7,864
Adjustment in fair value of derivatives	—	—	—	—	(11,111)	(11,111)
Balance, December 31, 2005	$ 326,617	$ 16,462	$ 49,921	$ 11,522	$ (3,237)	$ 401,285

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(1) Includes Senior Subordinated Series B Units which automatically converted to common units fourteen days after issuance. See Note 6(a).

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income
December 31, 2005, 2004 and 2003

	2005	2004	2003
		(In thousands)	
Net income	$ 19,200	$ 23,704	$ 15,226
Hedging gains or losses reclassified to earnings	7,864	(4,015)	4,267
Adjustment in fair value of derivatives	(11,111)	2,642	(1,708)
Comprehensive income	$ 15,953	$ 22,331	$ 17,785

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 19,200	$ 23,704	$ 15,226
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	36,024	23,034	13,268
Gain on sale of property	(8,138)	(12)	—
Minority interest in earnings	441	289	—
Deferred tax expense (benefit)	216	(190)	—
Loss on investment in affiliated partnerships	—	(304)	(208)
Non-cash stock-based compensation	3,672	1,001	5,345
Amortization of debt issue costs	1,127	1,016	366
Non-cash derivatives (gain) loss	10,208	(279)	361
Changes in assets and liabilities, net of acquisition effects:			
Accounts receivable and accrued revenue	(165,990)	(47,604)	(33,143)
Prepaid expenses, natural gas storage and other	(1,719)	(2,682)	(754)
Accounts payable, accrued gas purchases, and other accrued liabilities	132,932	50,676	41,084
Fair value of derivatives	(13,963)	(473)	(569)
Other	—	(73)	5,484
Net cash provided by operating activities	14,010	48,103	46,460
Cash flows from investing activities:			
Additions to property and equipment	(120,490)	(45,984)	(39,003)
Acquisitions and asset purchases	(505,518)	(78,895)	(68,124)
Proceeds from sales of property	10,991	611	—
Additions to other non-current assets	—	(115)	(1,027)
Distributions from (investments in) affiliated partnerships	—	12	(2,135)
Net cash used in investing activities	(615,017)	(124,371)	(110,289)
Cash flows from financing activities:			
Proceeds from borrowings	1,798,250	491,500	320,100
Payments on borrowings	(1,424,300)	(403,550)	(281,900)
Increase (decrease) in drafts payable	(8,812)	28,221	(17,100)
Debt refinancing costs	(6,919)	(1,370)	(1,735)
Contributions from minority interest party	786	990	—
Distribution to partners	(43,307)	(34,317)	(15,280)
Proceeds from exercise of unit options	1,345	425	—
Net proceeds from common unit offerings	223,340	—	57,336
Net proceeds from issuance of subordinated units	49,915	—	—
Contribution from partners	6,317	—	1,266
Net cash provided by financing activities	596,615	81,899	62,687
Net increase (decrease) in cash and cash equivalents	(4,392)	5,631	(1,142)
Cash and cash equivalents, beginning of period	5,797	166	1,308
Cash and cash equivalents, end of period	$ 1,405	$ 5,797	$ 166
Cash paid for interest	$ 14,598	$ 7,556	$ 3,388
Cash paid for income taxes	$ 496	$ 380	—

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements

(1) Organization and Summary of Significant Agreements

(a) Description of Business

Crosstex Energy, L.P. (the Partnership), a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids. The Partnership connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of natural gas liquids or NGLs, transports natural gas and ultimately provides an aggregated supply of natural gas to a variety of markets. In addition, the Partnership purchases natural gas from producers not connected to its gathering systems for resale and sells natural gas on behalf of producers for a fee.

(b) Partnership Ownership

Crosstex Energy GP, L.P., the general partner of the Partnership, is wholly owned by Crosstex Energy, Inc. (CEI). CEI also owned 9,334,000 subordinated units and 666,000 common units in the Partnership through its wholly-owned subsidiaries on December 31, 2005. As of December 31, 2005, CEI owned 38.0% of the limited partner interests in the Partnership and officers and directors owned 1.01% of the limited partnership interests. The remaining units are held by the public. As of December 31, 2005, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. (collectively, Yorktown) owned 23% of CEI and Crosstex Energy Services, L.P. (CES) management and directors owned 13% of CEI.

In February 2006 2,333,000 of CEI's subordinated units converted to common so that the current ownership of subordinated units is 7,001,000 and common units is 2,999,000.

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities, and results of operations of the Partnership and its wholly-owned subsidiaries. The Partnership proportionately consolidates its undivided 12.4% interest in a carbon dioxide processing plant acquired by the Partnership in June 2004 and its undivided 23.85% interest in a gas plant acquired by the Partnership in November 2005. In January 2004, the Partnership adopted FASB Interpretation No. 46R, *Consolidation of Variable Interest* Entities ("FIN No. 46R") and began consolidating its joint venture interest in Crosstex DC Gathering, J.V. as discussed more fully in Note 4. The consolidated operations are hereafter referred to herein collectively as the "Partnership." 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 Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(b) Cash and Cash Equivalents

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

(c) Inventories

Our inventories of products consist of natural gas and natural gas liquids. We report 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, natural gas liquids pipelines, natural gas processing plants, natural gas liquids (NGLs) fractionation plants, an undivided 12.4% interest in a carbon dioxide processing plant, and gas treating plants.

Other property and equipment is primarily comprised of computer software and equipment, furniture, fixtures, leasehold improvements, and office equipment. Such items are depreciated over their estimated useful life of three to seven years. 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. During 2005 interest of $0.9 million was capitalized to the North Texas Pipeline fixed asset projects under SFAS No. 34. Depreciation is provided using the straight-line method based on the estimated useful life of each asset, as follows:

	Useful Lives
Transmission assets	15-25 years
Gathering systems	7-15 years
Gas treating, gas processing and carbon dioxide plants	15 years
Other property and equipment	3-7 years

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If 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. No impairments were required during the three-year period ended December 31, 2005.

When determining whether impairment of one of our long-lived assets has occurred, the Partnership must estimate the undiscounted cash flows attributable to the asset. The Partnership's estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas 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 would require us to record an impairment of an asset.

(e) Goodwill and Intangibles

The Partnership has approximately $6.6 million of net goodwill at December 31, 2005. During the formation of the Partnership in May 2001, $5.4 million of goodwill was created and later amortized by $0.5 million. Approximately $1.7 million of goodwill resulted from the Cardinal acquisition in May 2005. The original goodwill has been allocated to the Midstream segment and the goodwill resulting from the Cardinal acquisition is allocated to the Treating segment and is assessed at least annually for impairment. During the fourth quarter of 2005, the Partnership completed the annual impairment testing of goodwill and no impairment was required.

Intangible assets consist of customer relationships. The November 2005 El Paso acquisition, as discussed in Note (3), added $253.8 million of such intangibles. The 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 equaling a weighted average amortization period for those customer relationship of 14.7 years. Such amortization was approximately $4.3 million, $1.2 million and $0.9 million for the years ended December 31, 2005, 2004 and 2003, respectively. As of December 31, 2005, accumulated amortization of intangible assets was $7.7 million.

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

2006	$ 18,528
2007	18,192
2008	17,951
2009	17,178
2010	16,984
Thereafter	166,364
Total	$ 255,197

(f) Other Assets

Unamortized debt issuance costs totaling $8.4 million as of December 31, 2005 are included in other assets, net. Debt issuance costs are amortized into interest expense over the term of the related debt. Other assets, net as of December 31, 2005 also includes the noncurrent portion of the note receivable from RLAC Gathering Group, L.P., the minority interest partner in the CDC joint venture discussed in Note 4.

(g) Gas Imbalance Accounting

Quantities of natural gas 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. The Partnership had imbalance payables of $30.5 million and $2.0 million at December 31, 2005 and 2004, respectively, which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $7.8 million and $0.6 million at December 31, 2005 and 2004, respectively, which are carried at the lower of cost or market value.

(h) Revenue Recognition

The Partnership recognizes revenue for sales or services at the time the natural gas, carbon dioxide, or NGLs are delivered or at the time the service is performed. See discussion of accounting for energy trading activities in note 2(i).

(i) Commodity Risk Management

The Partnership engages in price risk management activities in order to minimize the risk from market fluctuation in the price of natural gas and NGLs. To qualify as a hedge, the price movements in the commodity derivatives must be highly correlated with the underlying hedged commodity. Gains and losses related to commodity derivatives which qualify as hedges are recognized in income when the underlying hedged physical transaction closes and are included in the consolidated statements of operations as a cost of gas purchased.

Effective January 1, 2001, the Partnership adopted Statement of Financial Accounting Standards No. 133 (SFAS 133), *Accounting for Derivative Instruments and Hedging Activities.* This standard requires recognition of all derivative and hedging instruments in the statements of financial position as either assets or liabilities and measures them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in 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. To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying item being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically.

Currently, some of the derivative financial instruments that qualify for hedge accounting are designated as cash flow hedges. The cash flow hedge instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the gain or loss on these derivative instruments is recorded in other comprehensive income in partners' equity and reclassified into earnings in the same period in which the hedged transaction closes. The asset or liability related to the derivative instruments is recorded on the balance sheet in fair value of derivative assets or liabilities. Any ineffective portion of the gain or loss is recognized in earnings immediately.

Certain derivative financial instruments that qualify for hedge accounting are not necessarily designated as cash flow hedges. These financial instruments and their physical quantities are marked to market and recorded on the balance sheet in fair value of derivative assets or liabilities with the related earnings impact recorded in the period transactions are entered into.

(j) Commercial Services

The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that the Partnership does not own. The Partnership refers to these activities as part of Commercial Services. 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 Partnership manages its price risk related to future physical purchase or sale commitments for its Commercial Services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance the Partnership's future commitments and significantly reduce its risk 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 under SFAS No. 133 and accordingly, the Partnership continues to use mark-to-market accounting for both physical and financial contracts of its Commercial Services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Partnership's Commercial Services natural gas marketing activities are recognized in earnings as gain or loss on derivatives immediately.

For each reporting period, the Partnership records the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period, in addition to the net realized gains or losses on settled contracts, is reported net as gain or loss on derivatives in the statements of operations.

Net margins earned on settled contracts from its producer services activities included in profit on energy trading activities in the consolidated statement of operations was $1.6 million, $2.2 million and $2.3 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Energy trading contract volumes that were physically settled were as follows (in MMBtus):

	Years Ended December 31,		
	2005	2004	2003
Volumes purchased and sold	66,065,000	76,576,000	94,572,000

(k) Comprehensive Income

Comprehensive income includes net income and other comprehensive income, which includes, but is not limited to, unrealized gains and losses on marketable securities, foreign currency translation adjustments, minimum pension liability adjustments, unrealized gains and losses on derivative financial instruments.

Pursuant to SFAS No. 133, the Partnership records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

(l) Income Taxes

The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The net tax basis in the Partnership's assets and liabilities is less than the reported amounts on the financial statements by approximately $82.3 million as of December 31, 2005.

The new LIG entities the Partnership formed to acquire the stock of LIG Pipeline Company and its subsidiaries, as discussed more fully in Note 3, are treated as taxable corporations for income tax purposes. The entity structure was formed to effect the matching of the tax cost to the Partnership of a step-up in the basis of the assets to fair market value with the recognition of benefits of the step-up by the Partnership. A deferred tax liability of $8.2 million was recorded at the acquisition date. The deferred tax liability represents future taxes payable on the difference between the fair value and tax basis of the assets acquired.

For the year ended December 31, 2005, the Partnership recognized a deferred tax expense of $.2 million and no current tax expense on the LIG entities' net taxable income. The Partnership through ownership of the LIG entities has a net operating loss carryforward of $4.8 million as of December 31, 2005 as a result of an allocation of losses from the sale of certain properties during 2005 and has recognized deferred tax assets for the future utilization of these loss carryforwards. Management believes that the LIG entities will generate sufficient future taxable income through remedial allocations of income and guaranteed payments to utilize the net operating loss carryforward before it expires in 2025.

The Partnership provides for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis that will reverse in future periods (in thousands):

	2005	2004
Current tax provision	—	$ 352
Deferred tax provision (benefit)	$ 216	(190)
	$ 216	$ 162
A reconciliation of the provision for income taxes for the taxable corporation is as follows (in thousands):		
Federal income tax at statutory rate (35%)	$ 206	$ 154
State income taxes, net	10	8
Tax provision	$ 216	$ 162
The principal component of the Partnership's net deferred tax liability is as follows (in thousands):		
Deferred income tax assets:		
Net operating loss carryforward — current	$ 712	—
Net operating loss carryforward — noncurrent	1,062	—
	$ 1,774	—
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets-current	$ (496)	—
Property, plant, equipment and intangible assets-noncurrent	(9,499)	$ (8,005)
	$ (9,995)	$ (8,005)
Net deferred tax liability	$ (8,221)	$ (8,005)

(m) Concentrations of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited since the Partnership's customers represent a broad and diverse group of energy marketers and end users. In addition, the Partnership continually monitors and reviews credit exposure to its marketing counter-parties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. See Note 10 for further discussion. The Partnership records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Partnership had a reserve for uncollectible receivables as of December 31, 2005 and December 31, 2004, of $0.3 million and $0.1 million, respectively.

During 2005, Formosa Hydrocarbons contributed 10.6% of the consolidated revenue of the Partnership. Prior to 2005 Kinder Morgan was the primary customer, contributing 10.2% in 2004 and 20.5% in 2003. As the Partnership continues to grow and expand, this relationship between individual customer sales and consolidated total sales is expected to continue to change. While these customers represent a significant percentage of revenues, the loss of either would not have a material adverse impact on the Partnership's results of operations.

(n) 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 discounted 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 years ended December 31, 2005, 2004 and 2003, such expenditures were not significant.

(o) Option Plans

The Partnership applies the provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), and the related interpretations in accounting for its option plan. In accordance with APB No. 25 for fixed stock and unit options, compensation is recorded to the extent the market value of the stock or unit exceeds the exercise price of the option at the measurement date. Compensation costs for fixed awards with pro rata vesting are recognized on a straight-line basis over the vesting period. In addition, compensation expense is recorded for variable options based on the difference between fair value of the stock or unit and exercise price of the options at period end. The Partnership will adopt SFAS No. 123(R) effective January 1, 2006 and apply the modified prospective transition method. Under this method awards that are granted, modified, repurchased, or cancelled after the date of adoption should be measured and accounted for in accordance with SFAS No. 123(R). Awards that are granted prior to the effective date should continue to be accounted for in accordance with SFAS No. 123 except that stock option expense for unvested options must be recognized in the income statement. We do not expect the impact on net income under SFAS No. 123(R) to materially differ from the amounts presented in the pro forma net income under SFAS No. 123.

Stock based compensation expense of $4.1 million, $1.0 million, and $5.3 million was recognized in 2005, 2004, and 2003, respectively. The portion of compensation expense for 2005 and 2004 related to operating activities was $0.4 million and $0.2 million, respectively, and the remaining expense for 2005 and 2004 of $3.7 million and $0.8 million, respectively, related to general and administrative activities. The stock based compensation expense recorded in 2005 $0.5 million was related to the accelerated vesting of 7,060 unit options and 10,000 CEI Common Share options and $1.5 million was related to amortization of restricted units and CEI restricted common shares. Stock based compensation expense for 2005 also includes $0.4 million of payroll taxes associated with CEI stock option exercises. CEI made a capital contribution to the Partnership to reimburse the payroll taxes related to the CEI stock option exercises.

Had compensation cost for the Partnership been determined based on the fair value at the grant date for awards in accordance with SFAS No. 123, *Accounting for Stock Based Compensation*, the Partnership's net income (loss) would have been as follows (in thousands except per unit amounts):

	Years Ended December 31,		
	2005	2004	2003
Net income, as reported	$ 19,200	$ 23,704	$ 15,226
Add: Stock-based employee compensation expense included in reported net income	4,057	1,001	5,345
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(4,445)	(1,228)	(5,594)
Pro forma net income	$ 18,812	$ 23,477	$ 14,977

	Years Ended December 31,		
	2005	2004	2003
Net income per limited partner unit, as reported:			
Basic	$ 0.56	$ 0.98	$ 0.89
Diluted	$ 0.51	$ 0.95	$ 0.88
Pro forma net income per limited partner unit:			
Basic	$ 0.53	$ 0.97	$ 0.87
Diluted	$ 0.50	$ 0.95	$ 0.86

The fair value of each option is estimated on the date of grant using the Black Scholes option-pricing model with the following weighted average assumptions used for grants in 2005, 2004, and 2003:

	Crosstex Energy, L.P.		
	2005	2004	2003
Weighted average dividend yield	5.5%	6.4%	9.8%
Weighted average expected volatility	33%	29%	24%
Weighted average risk free interest rate	3.83%	3.25%	2.65%
Weighted average expected life	5.0 years	4.9 years	4.3 years
Contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$8.42	$4.00	$1.28

	Crosstex Energy, Inc. 2004
Weighted average dividend yield	5.4%
Weighted average expected volatility	30%
Weighted average risk free interest rate	3.26%
Weighted average expected life	4.5 years
Contractual life	10 years
Weighted average of fair value of unit options granted	$4.76

No CEI options were granted to employees, officers or directors of the Partnership in 2003 and 2005. Stock-based compensation associated with the CEI option plan is recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership.

(p) Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS NO. 123R, *"Share-Based Payment,"* which requires compensation related to all stock-based awards, including stock options be recognized in the consolidated financial statements. The provisions of SFAS No. 123R are effective for the first annual reporting period that begins after June 15, 2005. We will adopt this standard on January 1, 2006 and will elect the modified-prospective transition method. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption should be measured and accounted for in accordance with SFAS No. 123R. The unvested portion of awards that are granted prior to the effective date will be accounted for in accordance with SFAS No. 123. We expect that stock option grants will continue to be a significant part of employee compensation, and therefore, SFAS No. 123R will have a significant impact on our financial statements. We do not expect SFAS No. 123R to significantly change recorded compensation expense related to grants of restricted Partnership units and restricted CEI shares. Had we adopted SFAS No. 123R in prior periods, we believe the impact of that standard would have approximated the impact of SFAS No. 123 as described in the *"Stock Based Employee Compensation"* disclosure of pro forma net income and earnings per share As of December 31, 2005, we had 0.7 million unit options and 50,000 CEI stock options outstanding that had not yet vested, with a remaining estimated fair value of $2.3 million and we had 0.2 million unvested restricted units and 0.2 million unvested restricted CEI shares with a remaining estimated fair value of $12.7 million. Based on these estimated fair values, we currently anticipate stock based compensation expense for 2006 will be $5.7 million.

In March 2005, the FASB issued Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations"* (FIN 47). FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, *"Accounting for Asset Retirement Obligations"*, 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, FIN 47 provides that a liability for the fair value of a conditional asset retirement obligation should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB Statement No. 143. FIN 47 is effective at December 31, 2005, and had no significant impact on the Partnership's financial position or results of operations.

In May 2005, the FASB issued SFAS No. 154, "*Accounting Changes and Error Corrections"* (SFAS 154) which replaces Accounting Principles Board Opinion No. 20 *"Accounting Changes"* and FASB Statement No. 3, *"Reporting Accounting Changes in Interim Financial Statements."* SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005, and requires retrospective application to prior period financial statements of voluntary changes in accounting principle, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. The consolidated financial position, results of operations or cash flows will only be impacted by SFAS 154 if the Partnership implements a voluntary change in accounting principle or corrects accounting errors in future periods.

(3) Significant Asset Purchases and Acquisitions

On June 30, 2003, the Partnership completed the acquisition of certain assets from Duke Energy Field Services, L.P. ("DEFS") for $68.1 million, including the effect of certain purchase price adjustments. The assets acquired included: the Mississippi pipeline system, a 12.4% interest in the Seminole gas processing plant, the Conroe gas plant and gathering system and the Alabama pipeline system. The Partnership has accounted for this acquisition as a business combination in accordance with SFAS No. 141, Business Combinations. We have utilized the purchase method of accounting for this acquisition with an acquisition date of June 30, 2003.

In April 2004, the Partnership acquired, through its wholly-owned subsidiary Crosstex Louisiana Energy, L.P., the LIG Pipeline Company and its subsidiaries (LIG Inc., Louisiana Intrastate Gas Company, L.L.C., LIG Chemical Company, LIG Liquids Company, L.L.C. and Tuscaloosa Pipeline Company) (collectively, "LIG") from American Electric Power ("AEP") in a negotiated transaction for $73.7 million. LIG consists of approximately 2,000 miles of gas gathering and transmission systems located in 32 parishes extending from northwest and north-central Louisiana through the center of the state to south and southeast Louisiana. The Partnership financed the acquisition through borrowings under its amended bank credit facility.

We have utilized the purchase method of accounting for this acquisition with an acquisition date of April 1, 2004. The purchase price and our allocation thereof are as follows (in thousands):

Cash paid to AEP	$ 70,509
Leased assets acquired	451
Direct acquisition costs	2,732
Total Purchase Price	$ 73,692
Assets acquired:	
Current assets	$ 45,602
Property, plant & equipment	87,142
Intangible assets	1,000
Liabilities assumed:	
Current liabilities	(51,857)
Deferred tax liability	(8,195)
Total Purchase Price	$ 73,692

Intangible assets relate to customer relationships and are being amortized over three years.

In November 2005, the Partnership acquired El Paso Corporation's processing and natural gas liquids business in south Louisiana for $481.0 million. The assets acquired include 2.3 billion cubic feet per day of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The Partnership financed the acquisition with net proceeds totaling $228.0 million from the issuance of common units and Senior Subordinated Series B Units (including the 2% general partner contributions totaling $4.7 million) and borrowings under its bank credit facility for the remaining balance.

We have utilized the purchase method of accounting for this acquisition with an acquisition date of November 1, 2005. The purchase price and our allocation thereof are as follows (in thousands):

Cash paid to El Paso Corporation (net of estimated working capital adjustment)	$ 477,851
Direct acquisition costs	3,125
Total Purchase Price	$ 480,976
Assets acquired:	
Current assets	$ 49,693
Property, plant & equipment	235,599
Intangible assets	253,775
Liabilities assumed:	
Current liabilities	(58,091)
Total Purchase Price	$ 480,976

Intangible assets relate to customer relationships and are being amortized over 15 years.

The preliminary purchase price allocation for the El Paso acquisition has not been finalized because the Partnership is still in the process of finalizing working capital settlements with El Paso Corporation and estimating potential contingent obligations associated with the assets acquired.

Operating results for the LIG assets and El Paso assets have been included in the Statements of Operations since April 1, 2004 and November 1, 2005, respectively. The following unaudited pro forma results of operations assume that the LIG acquisition and the El Paso acquisition occurred on January 1, 2004 (in thousands, except per unit amounts):

	Pro Forma (Unaudited) Years Ended December 31,	
	2005	2004
Revenue	$ 3,320,474	$ 2,512,665
Net income	$ 5,766	$ 28,714
Net income (loss) per limited partner unit		
Basic	$ (0.20)	$ 0.84
Diluted	$ (0.19)	$ 0.82
Weighted average limited partners' units outstanding		
Basic	24,713	24,662
Diluted	26,234	25,214

(4) Investment in Limited Partnerships and Note Receivable

The Partnership owns a 50% interest in Crosstex Denton County Gathering, J.V. ("CDC"). Prior to 2004, the Partnership accounted for its investment in CDC under the equity method. Under this method, the Partnership carried its investments at cost and recorded its equity in net earnings of the affiliated partnerships as income in other income (expense) in the consolidated statement of operations, and distributions received from them were recorded as a reduction in the Partnership's investment in the affiliated partnership. In January 2004, the Partnership began consolidating its investment in CDC pursuant to FIN No. 46R.

In connection with the formation of CDC, the Partnership agreed to loan the CDC partner up to $1.5 million for its initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to the Partnership attributable to CDC partner's 50% share of distributable cash flow to repay the loan. Any balance remaining on the note is due in August 2007. The current portion of loan receivable of $0.8 million from the CDC partner is included in notes receivable in the accompanying consolidated balance sheet as of December 31, 2005. The remaining balance of $0.4 million is included in other assets, net as of December 31, 2005.

Until December 31, 2004, the Partnership owned a 7.86% weighted average interest as the general partner in the five gathering systems of Crosstex Pipeline Partners, L.P. ("CPP") and a 20.31% interest as a limited partner in CPP. The Partnership accounted for its investment in CPP under the equity method for the years ended December 31, 2003 and 2004 because it exercised significant influence in operating decisions as a general partner in CPP.

Effective December 31, 2004, the Partnership acquired all of the outside limited and general partner interests of the CPP Partnership for $5.1 million. This acquisition makes the Partnership the sole limited partner and general partner of CPP, so the Partnership began consolidating its investment in CPP effective December 31, 2004.

(5) Long-Term Debt

As of December 31, 2005 and 2004, long-term debt consisted of the following (in thousands):

	2005	2004
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2005 and 2004 were 6.69% and 4.99%, respectively	$ 322,000	$ 33,000
Senior secured notes, weighted average interest rate of 6.64% and 6.95%, respectively	200,000	115,000
Note payable to Florida Gas Transmission Company	650	700
	522,650	148,700
Less current portion	(6,521)	(50)
Debt classified as long-term	$ 516,129	$ 148,650

Credit Facility. In 2005 the Partnership amended its $200 million senior secured credit facility to increase the credit facility to provide for $750 million at any one time outstanding and the issuance of letters of credit in the aggregate face amount of up to $300 million at any one time.

The facility used to finance a portion of the El Paso acquisition and will be used to finance the acquisition and development of gas gathering, treating, and processing facilities, as well as working capital, letters of credit, distributions and other general partnership purposes. At December 31, 2005, $407.0 million was outstanding under the facility, including $85.0 million of letters of credit, leaving approximately $343.0 million available for future borrowings. The facility will mature in March 2010, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the credit facility may be re-borrowed.

Obligations under the credit facility are secured by first priority liens on all of our material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in certain of our subsidiaries, and ranks *pari passu* in right of payment with the senior secured notes. The credit agreement is guaranteed by certain of our subsidiaries. We may prepay all loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

Under the amended credit agreement, borrowings bear interest at our option at the administrative agent’s reference rate plus 0% to 0.50% or LIBOR plus 1.00% to 2.00%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.00% to 2.00% per annum, plus a fronting fee of 0.125% per annum. We will incur quarterly commitment fees based on the unused amount of the credit facilities.

The credit agreement prohibits us from declaring distributions to unit-holders if any event of default, as defined in the credit agreement, exists or would result from the declaration of distributions. In addition, the bank credit facility contains various covenants that, among other restrictions, limit the Partnership’s ability to:

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make distributions;
- change the nature of its business;
- enter into certain commodity contracts;

- make certain amendments to the Partnership's agreement; and
- engage in transactions with affiliates.

The credit facility contains the following covenants requiring the Partnership to maintain:

- a maximum ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, (i) 5.25 to 1.00 for any fiscal quarter ending during the period commencing on the effective date of the credit facility and ending March 31, 2006, (ii) 4.75 to 1.00 for any fiscal quarter ending during the period commencing on April 1, 2006, and (iii) 4.00 to 1.00 for any fiscal quarter ending thereafter, pro forma for any asset acquisitions (but during an acquisition adjustment period (as defined in the credit agreement), the maximum ratio is increased to 4.75 to 1); and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, equal to 3.0 to 1.0.

Each of the following will be an event of default under the bank credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;
- certain judgments against us or any of our subsidiaries, in excess of certain allowances;
- certain ERISA events involving us or our subsidiaries;
- a change in control (as defined in the credit agreement); and
- the failure of any representation or warranty to be materially true and correct when made.

Senior Secured Notes. In June 2003, the Partnership entered into a master shelf agreement with an institutional lender pursuant to which it issued $30.0 million aggregate principal amount of senior secured notes with an interest rate of 6.95% and a maturity of seven years. In July 2003, the Partnership issued $10.0 million aggregate principal amount of senior secured notes pursuant to the master shelf agreement with an interest rate of 6.88% and a maturity of seven years. In June 2004, the master shelf agreement was amended, increasing the amount issuable under the agreement from $50.0 million to $125.0 million. In June 2004, the Partnership issued $75.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years. In June 2005, the master shelf agreement was amended, increasing the amount issuable under the agreement from $125.0 million to $200.0 million. In November 2005, the Partnership issued an $85.0 million aggregate principal amount of senior secured notes with an interest rate of 6.23% and a maturity of ten years.

These notes represent senior secured obligations of the Partnership and will rank at least *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with obligations of the Partnership under the credit facility, by first priority liens on all of its material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all its equity interests in certain of its subsidiaries. The senior secured notes are guaranteed by the Partnership's subsidiaries.

The initial $40.0 million of senior secured notes are redeemable, at our option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the master shelf agreement. The $75.0 million senior secured notes issued in June 2004 and the $85.0 million issued in November 2005 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance.

The master shelf agreement relating to the notes contains substantially the same covenants and events of default as the bank credit facility.

If an event of default resulting from bankruptcy or other insolvency events occurs, the senior secured notes will become immediately due and payable. If any other event of default occurs and is continuing, holders of at least 50.1% in principal amount of the outstanding notes may at any time declare all the notes then outstanding to be immediately due and payable. If an event of default relating to the nonpayment of principal, make-whole amounts or interest occurs, any holder of outstanding notes affected by such event of default may declare all the notes held by such holder to be immediately due and payable.

The Partnership was in compliance with all debt covenants at December 31, 2005 and 2004.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement, the lenders under the bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by the Partnership and its subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under the bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under the bank credit facility and the master shelf agreement.

Other Note Payable. In June 2002, as part of the purchase price of Florida Gas Transmission Company (FGTC), the Partnership issued a note payable for $0.8 million to FGTC that is payable in $0.1 million annual increments through June 2006 with a final payment of $0.6 million due in June 2007. The note bears interest payable annually at LIBOR plus 1%.

Maturities. Maturities for the long-term debt as of December 31, 2005 are as follows (in thousands):

2006	$ 6,521
2007	10,012
2008	9,412
2009	9,412
2010	342,293
Thereafter	145,000

(6) Partners' Capital

(a) Issuance of Common Units, Senior Subordinated Units and Senior Subordinated Series B Units

In September 2003, the Partnership completed a public offering of 3,450,000 common units at a public offering price of $17.99 per common unit. The Partnership received net proceeds of approximately $59.2 million, including an approximate $1.3 million capital contribution by its general partner in order to maintain its 2% interest. The net proceeds were used to repay borrowings outstanding under the bank credit facility of our operating partnership.

On June 24, 2005, the Partnership issued 1,495,410 senior subordinated units in a private equity offering for net proceeds of $51.1 million, including our general partner's $1.1 million capital contribution. The senior subordinated units were issued at $33.44 per unit, which represents a discount of 13.7% to the market value of common units on such date, and automatically converted to common units on a one-for-one basis on February 24, 2006. The senior subordinated units received no distributions until their conversion to common units.

On November 1, 2005, the Partnership issued 2,850,165 Senior Subordinated Series B Units in a private placement for a purchase price of $36.84 per unit. We received net proceeds of approximately $107.1 million, including our general partner's $2.1 million capital contribution and net of expenses associated with the sale. The

Senior Subordinated Series B Units automatically converted into common units on November 14, 2005 at a ratio of one common unit for each Senior Subordinated Series B Unit. The Senior Subordinated Series B Units were not entitled to distributions paid on November 14, 2005. The net proceeds were used to fund a portion of the El Paso acquisition.

In November and December 2005, the Partnership issued 3,731,050 additional common units to the public at a purchase price of $33.25 per unit. The offering resulted in net proceeds to the Partnership of approximately $120.9 million including the general partner's $2.5 million capital contribution and net of expenses associated with the offering. The net proceeds from this offering were used to fund a portion of the El Paso acquisition.

(b) Limitation of Issuance of Additional Common Units

During the subordination period, the Partnership may issue up to 2,633,000 additional common units or an equivalent number of securities ranking on parity with the common units without obtaining unitholder approval. The Partnership may also issue an unlimited number of common units during the subordination period for acquisitions, capital improvements or debt repayments that increase cash flow from operations per unit on a pro forma basis.

(c) Subordination Period

The subordination period will end once the Partnership meets the financial tests in the partnership agreement, but it generally cannot end before December 31, 2007 except as discussed in (d) below. When the subordination period ends, each remaining subordinated units will convert into one common unit and the common units will no longer be entitled to arrearages.

(d) Early Conversion of Subordinated Units

If the Partnership meets the applicable financial tests in the partnership agreement for the three consecutive four-quarter periods ending on December 31, 2005 or December 31, 2006, up to 4,666,000 of the subordinated units may be converted into common units prior to December 31, 2007. The Partnership met the financial tests for three consecutive four-quarter periods ended December 31, 2005, so 2,333,000 subordinated units converted to common units upon the payment of the fourth quarter distribution on February 15, 2006. If the Partnership meets these tests for the three consecutive four-quarter periods ending on or after December 31, 2006, an additional 2,333,000 of the subordinated units will convert to common units.

(e) Cash Distributions

In accordance with the partnership agreement, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter commencing with the quarter ended on March 31, 2003. Distributions will generally be made 98% to the common and subordinated unit-holders and 2% 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. The Partnership's senior secured credit facility prohibits the Partnership from declaring distributions to unitholders if any event of default exists or would result from the declaration of distributions. See Note (5) for a description of the bank credit facility covenants.

Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $10.8 million, $5.6 million and $1.0 million were earned by our general partner for the years ended December 31, 2005, 2004 and 2003, respectively. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter. The Partnership paid annual per common unit distributions of $1.93, $1.70 and $1.288 for the years ended December 31, 2005, 2004 and 2003, respectively.

The Partnership increased its fourth quarter distribution on its common and subordinated units to $0.51 per unit which was paid on February 15, 2006.

(7) Retirement Plans

The Partnership sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The Partnership made year end discretionary contributions to the plan of $0.3 million for the year ended December 31, 2003. During 2004 the Partnership amended the plan to allow for contributions to be made at each compensation calculation period based on the annual discretionary contribution rate. Contributions of $0.6 million and $0.5 million were made to the plan for the years ended December 31, 2005 and December 31, 2004, respectively.

(8) Employee Incentive Plans

(a) Long-Term Incentive Plan

In December 2002, the Partnership’s managing general partner 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 2,600,000 common unit options and restricted units. The plan is administered by the compensation committee of the managing general partner’s board of directors.

(b) Restricted Units

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

Restricted units totaling 98,150 and 163,934 were issued in 2003 and 2005, respectively, to senior management, employees and directors with an intrinsic value equal to $1.3 million and $6.0 million, respectively. The units issued in 2003 vest over a five-year period and the units issued in 2005 vest over a three-year period. The intrinsic value of the units will be amortized into stock-based compensation over the vesting period. The Partnership recognized stock-based compensation expense of $1.2 million, $0.3 million and $0.2 million related to the amortization of these restricted units in 2005, 2004 and 2003, respectively.

(c) Unit Options

Unit options will have an exercise price that, in the discretion of the compensation committee, may be less than, equal to or more than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, or its general partner, or managing general partner.

A summary of the unit option activity for the years ended December 31, 2005, 2004 and 2003 is provided below:

	Years Ended December 31,					
	2005		2004		2003	
	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	1,043,865	$ 15.58	643,272	$ 10.28	350,000	$ 10.00
Granted	193,511	32.78	466,296	22.52	294,772	10.61
Exercised	(127,097)	10.57	(39,066)	11.00	—	—
Forfeited	(70,447)	23.15	(26,637)	15.64	(1,500)	10.00
Outstanding, end of period	1,039,832	$ 18.88	1,043,865	$ 15.58	643,272	$ 10.28
Options exercisable at end of period	308,455	$ 11.34	263,078	$ 10.36	143,334	$ 10.00
Weighted average fair value of options granted with an exercise price equal to market price at grant	—	—	116,902	$ 4.91	284,020	$ 1.16
Weighted average fair value of options granted with an exercise price less than market price at grant	193,511	$ 8.42	349,394	$ 3.70	10,752	$ 3.54

The following table summarizes information about outstanding options as of December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 0.00 - $10.63	433,053	7.03	$ 10.00	275,593	$ 10.00
$10.64 - $18.25	53,168	7.88	16.66	18,583	16.74
$18.26 - $23.90	281,029	7.86	21.27	4,948	22.65
$23.91 - $30.00	90,490	8.61	27.24	—	—
$30.01 - $34.14	182,092	9.48	32.82	9,331	34.03
Total	1,039,832	7.86	$ 18.88	308,455	$ 11.34

The Partnership currently accounts for option grants in accordance with APB No. 25, *Accounting for Stock Issued to Employees* and follows the disclosure only provision of SFAS No. 123, *Accounting for Stock-based Compensation.* The Partnership will adopt SFAS No. 123R effective January 1, 2006 and apply the modified prospective transition method. Under this method awards that are granted, modified, repurchased, or canceled after the date of adoption should be measured and accounted for in accordance with SFAS No. 123R. The unvested portion of awards that are granted prior to the effective date will be accounted for in accordance with SFAS No. 123. In September 2003, two directors elected to receive options to purchase 10,752 common units (in aggregate) in the Partnership in payment of their 2003 annual director fees. The options vest over a three-year period with an exercise price of $11.63 per common unit. Since the exercise price was below the market price on the grant date, the Partnership recorded stock-based compensation of $27,000 in 2003 to recognize the vesting of a portion of such options during 2003.

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

CEI has one stock-based compensation plan, the Crosstex Energy, Inc. Long-Term Incentive Plan. The plan currently permits the grant of awards covering an aggregate of 1,200,000 options for common stock and restricted shares. The plan is administered by the Compensation Committee of the Company's board of directors.

CEI currently applies the provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), and the related interpretations in accounting for the plan. In accordance with APB No. 25, compensation is recorded to the extent the fair value of the stock exceeds the exercise price of the option at the measurement date. Compensation costs for fixed awards with pro rata vesting are recognized on a straight-line basis over the vesting period. The Company will adopt SFAS No. 123R effective January 1, 2006 and apply the modified prospective transition method. Under this method awards that are granted, modified, repurchased, or canceled after the date of adoption should be measured and accounted for in accordance with SFAS No. 123R. Awards that are granted prior to the effective date should continue to be accounted for in accordance with SFAS No. 123 except that stock option expense for unvested options must be recognized in the income statement.

Compensation expense related to options for which variable accounting is required is recorded based on the difference between fair value of the stock or unit and exercise price of the options at period end. Compensation expense of $47,000 and $5.0 million was recognized in 2004 and 2003, respectively, related to CEI's stock options. Stock-based compensation associated with the CEI option plan is recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership. As discussed below, CEI modified certain outstanding options during 2003 which were accounted for using variable accounting.

A summary of the status of the 2000 Stock Option Plan as of December 31, 2005, 2004 and 2003, is presented in the table below (all amounts have been adjusted to reflect the two-for-one stock split made by CEI in connection with its January 2004 initial public offering):

	Years Ended December 31,					
	2005		2004		2003	
	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	720,384	$ 6.66	862,390	$ 5.42	1,040,500	$ 5.39
Granted	22,986	41.55	43,636	25.44	—	—
Cancelled	(9,020)	21.30	(8,000)	5.13	(176,110)	5.20
Exercised	(681,039)	5.60	(177,642)	5.34	—	—
Forfeited	—	—	—	—	(2,000)	6.00
Outstanding, end of period	53,311	$ 32.73	720,384	$ 6.66	862,390	$ 5.42
Options exercisable at end of period	3,311	$ 37.74	662,083	$ 5.55	711,213	$ 5.29
Weighted average fair value of options granted with an exercise price equal to market price at grant	22,986	$ 11.05	40,000	$ 4.50	—	—
Weighted average fair value of options granted with an exercise price less than market at grant	—	—	3,636	$ 7.58	—	—

The following table summarizes information about outstanding options as of December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Number**	**Weighted Average Remaining Term**	**Weighted Average Exercise Price**	**Number**	**Weighted Average Exercise Price**
$19.50	30,000	9.0	$ 19.50	—	$ 19.50
$34.37	1,818	9.0	$ 34.37	1,818	$ 34.37
$40.00	10,000	8.9	$ 40.00	—	$ 40.00
$41.50	10,000	9.0	$ 41.50	—	$ 41.50
$41.85	1,493	9.3	$ 41.85	1,493	$ 41.85
Total	53,311	9.0	$ 32.73	3,311	$ 37.74

CEI modified certain outstanding options attributable to its common shares in the first quarter of 2003, which allowed the option holders to elect to be paid in cash for the modified options based on the fair value of the options. The total number of CEI options which were modified was approximately 364,000. These modified options were accounted for using variable accounting as of the option modification date. The Partnership applied variable accounting for the modified options until the holders elected to cash out the options or the election to cash out the options lapsed. CEI was responsible for paying the intrinsic value of the options for the holders who elected to cash out their options. December 31, 2003 was the last valuation date that a holder of modified options could elect the cash-out alternative. Accordingly, effective January 1, 2004, the Partnership ceased applying variable accounting for the remaining modified options. The Partnership recognized stock-based compensation expense of approximately $5.0 million related to the modified options for the year ended December 31, 2003.

Restricted shares in CEI were issued to members of management under its long-term incentive plan in 2003 and 2005. CEI issued 124,880 restricted shares in 2005 and 85,000 in 2003 with an intrinsic value of $6.4 million and $2.6 million, respectively. Vesting of 80,000 of the CEI restricted shares is over a five-year period and 129,880 of the restricted shares vest over a three-year period. The intrinsic value of the restricted shares is amortized into stock-based compensation expense over the vesting periods.

(e) Earnings per unit and anti-dilutive computations

Basic earnings per unit was computed by dividing net income by the weighted average number of limited partner units (including restricted units) outstanding for the years ended December 31, 2005 and December 31, 2004. The computation of diluted earnings per unit further assumes the dilutive effect of unit options and restricted units.

Effective March 29, 2004, the Partnership completed a two-for-one split on its outstanding limited partnership units. All unit amounts for prior periods presented herein have been restated to reflect this unit split.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2005, 2004, and 2003 (in thousands, except per-unit amounts):

	Years Ended December 31,		
	2005	2004	2003
Basic earnings per unit:			
Weighted average limited partner units outstanding	19,006	18,081	15,752
Dilutive earnings per unit:			
Weighted average limited partner units outstanding	19,006	18,081	15,752
Dilutive effect of restricted units	162	98	—
Dilutive effect of senior subordinated units	773	—	—
Dilutive effect of exercise of options outstanding	586	454	208
Dilutive units	20,527	18,633	15,960

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented

	Years Ended December 31,		
	2005	2004	2003
Income allocation for incentive distributions	$ 10,660	$ 5,550	$ 954
Stock-based compensation attributable to CEI’s stock options and restricted shares	(2,223)	—	—
2% general partner interest in net income	215	363	286
General Partner Share of Net Income	$ 8,652	$ 5,913	$ 1,240

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note 6(e). In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to CEI stock options and restricted stock all to the general partner to match the related general partner contribution.

(9) Fair Value of Financial Instruments

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

	2005		2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 1,405	$ 1,405	$ 5,797	$ 5,797
Trade accounts receivable and accrued revenues	428,869	428,869	231,153	231,153
Fair value of derivative assets	19,838	19,838	3,191	3,191
Note receivable	1,276	1,276	1,653	1,653
Accounts payable, drafts payable and accrued gas purchases	406,860	406,860	255,700	255,700
Current portion long-term debt	6,521	6,521	50	50
Long-term debt	516,129	520,005	148,650	157,181
Fair value of derivative liabilities	18,359	18,359	2,219	2,219

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities. The carrying value for the note receivable approximates the fair value because this note earns interest based on the current prime rate.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $322.0 million and $33.0 million as of December 31, 2005 and 2004, 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, 2005, the Partnership also had borrowings totaling $200 million under senior secured notes with a weighted average interest rate of 6.64%. The fair value of these borrowings as of December 31, 2005 and 2004 were adjusted to reflect to current market interest rate for such borrowings as of December 31, 2005 and 2004, 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.

(10) Derivatives

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", and "storage 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.

In August 2005 the Partnership acquired puts, or rights to sell a portion of the liquids from the plants at a fixed price over a two-year period beginning January 1, 2006 for a premium of $18.7 million as part of the overall risk management plan related to the acquisition of the El Paso assets which closed on November 1, 2005. In December 2005 the Partnership sold a portion of those puts for $4.3 million. The Partnership did not designate these put options to obtain hedge accounting as of December 31, 2005 and therefore, these put options did not qualify as hedges as of December 31, 2005 and were marked to market through our consolidated statement of operations. The puts represent options, but not obligations, to sell the related underlying liquids volumes at a fixed price. As the price of the underlying liquids increased significantly in the period, the value of the put options declined and is reflected in gain/loss on derivatives.

The components of gain/loss on derivatives in the Consolidated Statements of Operations are (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Change in fair value of derivates that do not qualify for hedge accounting	$ 9,929	$ (262)	$ 361
Ineffective portion of derivatives qualifying for hedge accounting	39	(17)	—
	$ 9,968	$ (279)	$ 361

The fair value of derivative assets and liabilities, excluding the interest rate swap, are as follows (in thousands):

	December 31,	
	2005	2004
Fair value of derivative assets — current	$ 12,205	$ 3,025
Fair value of derivative assets — long term	7,633	166
Fair value of derivative liabilities — current	(14,782)	(2,085)
Fair value of derivative liabilities — long term	(3,577)	(134)
Net fair value of derivatives	$ 1,479	$ 972

Set forth below is the summarized notional amount and terms of all instruments held by us for price risk management purposes at December 31, 2005 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than October 2009. The Partnership's counterparties to derivative contracts include BP Corporation, Total Gas & Power and J. Aron & Co., a subsidiary of Goldman Sachs. Changes in the fair value of the Partnership's derivatives related to third-party producers and customers gas marketing activities 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 and the ineffective portion is recorded in earnings.

December 31, 2005

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Cash Flow Hedges:				
Natural gas swaps	2,264,000	NYMEX less a basis of $2.495 to NYMEX plus a basis of $0.01 or prices ranging from $6.86 to $11.441 settling against various Inside FERC Index prices	January 2006 — March 2006	$ (533)
Natural gas swaps	(10,190,000)		January 2006 — December 2006	(3,198)
Total natural gas swaps designated as cash flow hedges				$ (3,731)
Liquids swaps	(41,789,752)	Fixed prices ranging from $0.69 to $1.39 settling against Mt. Belvieu Average of daily postings (non-TET)	January 2006 — December 2007	$ 437
Total liquids swaps designated as cash flow hedges				$ 437
Mark to Market Derivatives:				
Swing swaps	1,431,239	Prices ranging from Inside FERC Index less $0.0575 to Inside FERC Index plus $0.15 settling against various Inside FERC Index prices.	January 2006	$ (851)
Swing swaps	(2,399,214)		January 2006	823
Total swing swaps				$ (28)
Physical offset to swing swap transactions	2,399,214	Prices of various Inside FERC Index prices settling against various Inside FERC Index prices	January 2006	—
Physical offset to swing swap transactions	(1,431,239)		January 2006	—
Total physical offset to swing swaps				$ —
Third party on-system financial swaps	5,153,800	Fixed prices ranging from $5.659 to $14.865 settling against various Inside FERC Index prices	January 2006 — October 2009	$ 6,217
Third party on-system financial swaps	(298,000)		January 2006 — March 2006	207
Total third party on-system financial swaps				$ 6,424
Physical offset to third party on-system transactions	(5,153,800)	Fixed prices ranging from $5.71 to $14.82 settling against various Inside FERC Index prices	January 2006 — October 2009	$ (5,794)
Physical offset to third party on-system transactions	298,000		January 2006 — March 2006	(197)
Total physical offset to third party on-system swaps				$ (5,991)
Marketing trading financial swaps	(417,000)	Fixed prices ranging from $7.35 to $13.4225 settling against various Inside FERC Index prices	January 2006 — March 2006	$ (587)
Marketing trading financial swaps	—		—	—
Total marketing trading financial swaps				$ (587)
Physical offset to marketing trading transactions	417,000	Fixed prices ranging from $7.30 to $13.40 settling against various Inside FERC Index prices	January 2006 — March 2006	$ 604
Physical offset to marketing trading transactions	—		—	—
Total physical offset to marketing trading transactions swaps				$ 604
Storage swap transactions:				
Storage swap transactions	355,000	Fixed prices ranging from $8.01 to $14.370 settling against various Inside FERC Index prices	January 2006	$ (817)
Storage swap transactions	(710,000)		January 2006 — March 2006	(56)
Total financial storage swap transactions				$ (873)
Natural gas liquid puts:				
Liquid put options (purchased)	160,995,660	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu Average Daily Index	January 2006 — December 2007	$ 9,847
Liquid put options (sold)	(73,569,998)	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu Average Daily Index	January 2006 — December 2007	(4,623)
Total natural gas liquid puts				$ 5,224

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.

Impact of Cash Flow Hedges

Natural Gas

For the year ended December 31, 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $7.0 million. For the year ended December 31, 2004, net losses on futures and basis swap hedge contracts decreased gas revenue by $0.9 million. As of December 31, 2005, an unrealized pre-tax derivative fair value gain of $3.7 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). This entire fair value loss is expected to be reclassified into earnings through December 2006. 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.

The settlement of futures contracts and basis swap agreements related to January 2006 gas production reduced gas revenue by approximately $0.7 million.

Liquids

For the year ended December 31, 2005, net losses on liquids swap hedge contracts decreased liquids revenue by approximately $1.2 million. For the year ended December 31, 2005, an unrealized pre-tax derivative fair value gain of $0.4 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). This entire fair value gain is expected to be reclassified into earnings in 2006 and in 2007. 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.

Assets and liabilities related to third party derivative contracts, swing swaps, storage swaps and puts 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 on a net basis 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**	**Two to Three Years**	**Total Fair Value**
December 31, 2005	$ 926	$ 3,829	$ 18	$ 4,773

(11) Transactions with Related Parties

General and Administrative Expense Cap

The Partnership had a $6.0 million annual ($1.5 million quarterly) general and administrative cap for the twelve-month period ended in December 2003, per the partnership agreement. CEI bore the cost of any excess general and administrative expenses. During the year ended December 31, 2003, the Partnership had excess expenses of approximately $3.5 million. The general partner was also reimbursed for direct charges it incurs on behalf of partnership business development activities. Such charges totaled $0.8 million for the year ended December 31, 2003 and are included in general and administrative expenses.

Camden Resources, Inc.

The Partnership treats gas for and purchases gas from, Camden Resources, Inc. (Camden). Camden is an affiliate of the Partnership by way of equity investments made by Yorktown in Camden. During the years ended December 31, 2005, 2004 and 2003, the Partnership purchased natural gas from Camden in the amount of approximately $67.2 million, $38.4 million, and $8.4 million, respectively, and received approximately $2.6 million, $2.4 million, and $0.2 million, respectively, in treating fees from Camden.

Crosstex Pipeline Partners, L.P.

Prior to December 31, 2004, the Partnership was the general partner and a limited partner in CPP as discussed in Note 4. The Partnership had related-party transactions with CPP, as summarized below:

- During the years ended December 31, 2004 and 2003, the Partnership bought natural gas from CPP in the amount of approximately $11.6 million and $8.2 million and paid approximately $51,000 and $41,000, respectively, to CPP for transportation.
- During the years ended December 31, 2004 and 2003, the Partnership received a management fee from CPP in the amount of approximately $125,000 and $125,000, respectively.
- During the years ended December 31, 2004 and 2003, the Partnership received distributions from CPP in the amount of approximately $159,000 and $104,000, respectively.

Effective December 31, 2004, the Partnership acquired all of the outside limited and general partner interests of the CPP Partnership for $5.1 million. This acquisition makes the Partnership the sole limited partner and general partner of CPP, so the Partnership began consolidating its investment in CPP effective December 31, 2004.

(12) Commitments and Contingencies

(a) Leases — Lessee

The Partnership has operating leases for office space, office and field equipment and the Eunice plant. The Eunice plant operating lease acquired in the El Paso acquisition provides for annual lease payments of $12.19 million with a lease term extending to November 20, 2012. At the end of the lease term the Partnership has the option to purchase the plant for $66.25 million.

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 millions):

2006	$ 14.6
2007	14.4
2008	14.1
2009	13.8
2010	13.5
Thereafter	23.7
	$ 94.1

Operating lease rental expense in the years ended December 31, 2005, 2004 and 2003, was approximately $3.4 million, $2.8 million, and $1.8 million, respectively.

(b) Leases — Lessor

During 2005, the Partnership leased approximately 32 of its treating plants and 24 of its dewpoint control plants to customers under operating leases. The initial terms on these leases are generally 24 months, at which time the leases revert to 30-day cancelable leases. As of December 31, 2005, the Partnership only had five treating plants under operating leases with remaining non-cancelable lease terms in excess of one year. The future minimum lease rentals are $1.6 million and $0.4 million for the years ended December 31, 2006 and 2007, respectively. These leased treating plants have a cost of $9.7 million and accumulated depreciation of $0.9 million as of December 31, 2005.

(c) Employment Agreements

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

(d) 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. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. The estimated remediation costs are expected to be approximately $0.3 million. Since this remediation project is a result of previous owners’ operation and the actual contamination occurred prior to the Partnership’s ownership, these costs were accrued as part of the purchase price.

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 Partnership 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 Partnership does not expect to incur any material environmental liability associated with these issues.

The Partnership acquired assets from Duke Energy Field Services, or DEFS, in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The estimated remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of the Conroe site. Moreover, a third-party company has assumed the remediation costs associated with the Conroe site. Therefore, the Partnership does not expect to incur any material environmental liability associated with the Conroe site.

(b) Other

The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

(13) Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the Mississippi System, the Conroe System, the Gulf Coast System, the Corpus Christi System, the Gregory Gathering System located around the Corpus Christi area, the Arkoma system in Oklahoma, the Vanderbilt System located in south Texas, the LIG pipelines and processing plants located in Louisiana, the South Louisiana processing and liquids assets, and various other small systems. Also included in the Midstream division are the Partnership's Producer Services operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or though fixed monthly payments. Included in the Treating division are four gathering systems that are connected to the treating plants and the Seminole plant located in Gaines County, Texas. During 2004, management decided that the Seminole plant, which was acquired in June 2003, should be included in the Treating division. Therefore, the 2003 segment information has been adjusted to reflect this reclassification.

The accounting polices of the operating segments are the same as those described in note 2 of the Notes to Consolidated Financial Statements. The Partnership evaluates the performance of its operating segments based on earnings before income taxes and accounting changes, and after an allocation of corporate expenses. Corporate expenses are allocated to the segments on a pro rata basis based on the number of employees within the segments. Interest expense is allocated on a pro rata basis based on segment assets. Inter-segment sales are at cost.

Summarized financial information concerning the Partnership's reportable segments is shown in the following table. There are no other significant non-cash items.

	Midstream	Treating	Totals
		(In thousands)	
Year ended December 31, 2005:			
Sales to external customers	$ 2,984,874	$ 48,606	$ 3,031,480
Inter-segment sales	10,003	(10,003)	—
Interest expense	13,365	2,402	15,767
Depreciation and amortization	25,085	10,938	36,024
Segment profit(a)	14,192	5,665	19,857
Segment assets	1,299,762	125,396	1,425,158
Capital expenditures (excludes acquisitions)	103,494	24,188	127,682
Year ended December 31, 2004:			
Sales to external customers	$ 1,948,021	$ 30,755	$ 1,978,776
Inter-segment sales	6,360	(6,360)	—
Interest expense	7,801	1,419	9,220
Depreciation and amortization	15,762	7,272	23,034
Segment profit	20,390	3,765	24,155
Segment assets	496,484	90,287	586,771
Capital expenditures (excludes acquisitions)	20,843	25,141	45,984
Year ended December 31, 2003:			
Sales to external customers	$ 989,697	$ 23,966	$ 1,013,663
Inter-segment sales	6,893	(6,893)	—
Interest expense	2,747	645	3,392
Depreciation and amortization	9,349	3,919	13,268
Segment profit (loss)	12,363	2,863	15,226
Segment assets	296,417	69,633	366,050
Capital expenditures (excludes acquisitions)	28,728	10,275	39,003

(a) Midstream profit is net of non-cash derivative loss of $10.2 million.

(14) Subsequent Event

Hanover Acquisition. On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.5 million. After this acquisition we have approximately 150 treating plants in operation and a total fleet of approximately 190 units.

(15) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
			(In thousands, except per unit data)		
2005					
Revenues	$ 549,471	$ 630,472	$ 782,451	$ 1,069,086	$ 3,031,480
Operating income	6,710	7,500	3,976	17,046	35,232
Net income	3,180	4,484	1,072	10,464	19,200
Earnings (loss) per limited partner unit-basic	$ 0.06	$ 0.18	$ (0.05)	$ 0.33	$ 0.56
Earnings (loss) per limited partner unit-diluted	$ 0.06	$ 0.17	$ (0.05)	$ 0.30	$ 0.51
2004					
Revenues	$ 325,358	$ 515,531	$ 508,884	$ 629,003	$ 1,978,776
Operating income	6,799	8,213	8,806	8,759	32,577
Net income	5,706	5,941	5,945	6,112	23,704
Earnings per limited partner unit — basic	$ 0.26	$ 0.25	$ 0.24	$ 0.23	$ 0.98
Earnings per limited partner unit — diluted	$ 0.24	$ 0.24	$ 0.23	$ 0.22	$ 0.95

Schedule II

CROSSTEX ENERGY, L.P.

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In thousands)		
Year ended December 31, 2005				
Allowance for doubtful accounts	$ 59	$ 200	—	$ 259
Year ended December 31, 2004				
Allowance for doubtful accounts	—	$ 59	—	$ 59
Year ended December 31, 2003				
Allowance for doubtful accounts	—	—	—	—

EXHIBIT INDEX

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Fourth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of November 1, 2005 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	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 our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-106927).
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.7 to Amendment No. 1 to our Registration Statement on Form S-3, file No. 333-128282).
4.2	—	Registration Rights Agreement, dated as of November 1, 2005, by and among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Tortoise Energy Capital Corp., Tortoise Energy Infrastructure Corporation and Fiduciary/Claymore MLP Opportunity Fund (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
4.3	—	Registration Rights Agreement, dated as of June 24, 2005, among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Tortoise Energy Capital Corporation and Tortoise Energy Infrastructure Corporation (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 24, 2005, filed with the Commission on June 4, 2005).
10.1	—	Fourth Amended and Restated Credit Agreement, dated as of November 1, 2005, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.2	—	Amended and Restated $125,000,000 Senior Secured Notes Master Shelf Agreement, dated as of March 31, 2005, among Crosstex Energy, L.P., Crosstex Energy Services, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 31, 2005, filed with the Commission on April 6, 2005).
10.3	—	Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated as of June 22, 2005, among Crosstex Energy, L.P., Crosstex Energy Services, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 27, 2005, filed with the Commission on June 28, 2005).
10.4	—	Letter Amendment No. 2 to Amended and Restated Master Shelf Agreement, dated as of November 1, 2005, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.5	—	Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 1, 2004).
10.6	—	First Amendment to Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 1, 2004).

Number		Description
10.7	—	Second Amendment to Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.3 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.8†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan, dated July 12, 2002 (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2002).
10.9†	—	Amendment to Crosstex Energy GP, LLC Long Term Incentive Plan dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.10	—	Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.11†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.12	—	Seminole Gas Processing Plant Gaines County, Texas Joint Operating Agreement dated January 1, 1993 (incorporated by reference to Exhibit 10.10 to our Registration Statement on Form S-1, file No. 333-106927).
10.13	—	Senior Subordinated Unit Purchase Agreement, by and among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Tortoise Energy Capital Corporation and Tortoise Energy Infrastructure Corporation (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 24, 2005, filed with the Commission on June 24, 2005).
10.14	—	Senior Subordinated Series B Unit Purchase Agreement, dated as of October 18, 2005, by and among Crosstex Energy, L.P., and the purchasers named thereon (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 18, 2005, filed with the Commission on October 19, 2005).
10.15	—	Purchase and Sale Agreement, dated as of August 8, 2005, by and between Crosstex Energy, L.P. and El Paso Corporation (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 8, 2005, filed with the Commission on August 11, 2005).
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.

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* Filed herewith.

† As required by Item 14(a)(3), this exhibit is identified as a compensatory benefit plan or arrangement.

Exhibit 21.1

LIST OF SUBSIDIARIES

Name of Subsidiary	State of Organization
Crosstex Operating GP, LLC	Delaware
Crosstex Energy Services GP, LLC	Delaware
Crosstex Energy Services, L.P.	Delaware
Crosstex Pipeline, LLC	Texas
Crosstex Pipeline Partners, Ltd.	Texas
Crosstex Gulf Coast Transmission Ltd.	Texas
Crosstex Gulf Coast Marketing Ltd.	Texas
Crosstex CCNG Gathering, Ltd.	Texas
Crosstex CCNG Transmission, Ltd.	Texas
Crosstex CCNG Processing, Ltd.	Texas
Crosstex Treating Services, L.P.	Delaware
Crosstex Alabama Gathering System, L.P.	Delaware
Crosstex Mississippi Industrial Gas Sales, L.P.	Delaware
Crosstex Mississippi Pipeline, L.P.	Delaware
Crosstex Seminole Gas, L.P.	Delaware
Crosstex Acquisition Management, L.P.	Delaware
Crosstex Louisiana Energy, L.P.	Delaware
LIG Chemical GP, LLC	Delaware
LIG Chemical, L.P.	Delaware
LIG Liquids Holdings, L.P.	Delaware
Crosstex LIG, LLC	Louisiana
Crosstex Tuscaloosa, LLC	Louisiana
Crosstex LIG Liquids, LLC	Louisiana
Crosstex DC Gathering Company, J.V.	Texas
Crosstex North Texas Pipeline, L.P.	Texas
Crosstex North Texas Gathering, L.P.	Texas
Crosstex Pelican, LLC	Delaware
Crosstex Processing Services, LLC	Delaware
Crosstex NGL Marketing, L.P.	Texas
Sabine Pass Plant Facility, J.V.	Texas

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.

We consent to the incorporation by reference in the registration statements No. 333-116538 and 333-128282 on Forms S-3 and S-8 of Crosstex Energy, L.P. (No. 333-107025 and 333-127645) of our reports dated March 10, 2006, with respect to the consolidated balance sheets of Crosstex Energy, L.P. as of December 31, 2005 and 2004, and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, and all related financial statement schedules, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005 and the effectiveness of internal control over financial reporting as of December 31, 2005, which reports appear in the December 31, 2005 annual report on Form 10-K of Crosstex Energy, L.P.

Our report dated March 13, 2005, on management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting as of December 31, 2005, contains an explanatory paragraph that states that the Partnership acquired CFS Louisiana Midstream Company and El Paso Dauphin Island Company, L.L.C. during 2005, and management excluded from its assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2005 any internal control evaluation over financial reporting associated with CFS Louisiana Midstream Company and El Paso Dauphin Island Company, L.L.C.'s total assets of $488.2 million and total revenues of $66.3 million included in the consolidated financial statements of Crosstex Energy, L.P. and subsidiaries as of and for the year ended December 31, 2005. Our audit of internal control over financial reporting of Crosstex Energy, L.P. also excluded an evaluation of the internal control over financial reporting of CFS Louisiana Midstream Company and El Paso Dauphin Island Company, L.L.C.

/s/ KPMG LLP

Dallas, Texas
March 13, 2006

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

1. I have reviewed this annual report on Form 10-K of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused the disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ Barry E. Davis

Barry E. Davis,
President and Chief Executive Officer
(principal executive officer)

Date: March __________, 2006

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

1. I have reviewed this annual report on Form 10-K of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused the disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ William W. Davis

William W. Davis,
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: March __________, 2006

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Crosstex Energy, L.P. (the “Registrant”) on Form 10-K for the year ended December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Barry E. Davis

Barry E. Davis
Chief Executive Officer

March __________, 2006

/s/ William W. Davis

William W. Davis
Chief Financial Officer

March __________, 2006

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.