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FORM 10-K

CROSSTEX ENERGY INC - XTXI

Filed: March 15, 2005 (period: December 31, 2004)

Annual report which provides a comprehensive overview of the company for the past year

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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, 2004

or

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

For the transition period from to

Commission file number: 000-50536

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

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

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

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

Title of Each Class	Name of Exchange on which Registered
None	Not applicable

Securities registered pursuant to Section 12(g) of the act:

Title of Class
Common Stock, Par Value $0.01 Per Share

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 an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☑ No ☐

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $115,156,373 on June 30, 2004, based on $40.10 per share, the closing price of the Common Stock as reported on the NASDAQ National Market on such date.

At March 7, 2005, there were outstanding 12,412,059 shares of common stock.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Registrant's Proxy Statement relating to its 2005 Annual Stockholders' Meeting to be filed with the Securities and Exchange Commission are incorporated by reference herein into Part III of this Report.

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DESCRIPTION

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC.

PART I

Item 1. *Business*

General

Crosstex Energy, Inc. is a Delaware corporation, formed in April 2000. We completed our initial public offering in January 2004. Our shares of common stock are listed on the NASDAQ National Market under the symbol "XTXI". Our executive offices are located at 2501 Cedar Springs, Suite 600, 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 "Crosstex Energy, Inc." as well as the terms "our," "we," and "us," or like terms, are sometimes used as references to Crosstex Energy, Inc. and its consolidated subsidiaries. References in this report to "Crosstex Energy, L.P.," the "Partnership," "CELP," or like terms refer to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. and its consolidated subsidiaries.

CROSSTEX ENERGY, INC.

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

- 666,000 common units and 9,334,000 subordinated units, representing a 54.2% limited partner interest in the Partnership; and
- 100% ownership interest in Crosstex Energy GP, L.P., the general partner of the Partnership, which owns a 2.0% general partner interest and all of the incentive distribution rights in the Partnership.

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

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

Distributions by the Partnership have increased from $0.25 per unit for the quarter ended March 31, 2003 (its first full quarter of operation after its initial public offering), to $0.45 per unit for the quarter ended December 31, 2004. As a result, our distributions from the Partnership pursuant to our ownership of our 10,000,000 common and subordinated units have increased from $2,500,000 for the quarter ended March 31, 2003 to $4,500,000 for the quarter ended December 31, 2004; our distributions pursuant to our 2% general partner interest have increased from $74,000 to $203,000; and our distributions pursuant to our incentive distribution rights have increased from nothing to $1,822,000. As a result, we have increased our dividend from $0.30 per share for the quarter ended March 31, 2004 (the first dividend payout after our initial public offering) to $0.39 per share for the quarter ended December 31, 2004.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

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

• federal income taxes, which we are required to pay because we are taxed as a corporation;

• the expenses of being a public company;

• other general and administrative expenses;

• capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner's 2.0% general partner interest; and

• reserves our board of directors believes prudent to maintain.

If the Partnership is successful in implementing its business strategy and increasing distributions to its partners, we would expect to continue to increase dividends to our stockholders, although the timing and amount of any such increased dividends will not necessarily be comparable to the increased Partnership distributions.

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

The Partnership's 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; improving the profitability of its assets by increasing their utilization while controlling costs; accomplishing economies of scale through new construction or expansion opportunities in its core operating areas; and maintaining financial flexibility to take advantage of opportunities. If the Partnership is successful in implementing this strategy, we believe the total amount of cash distributions it makes will increase and our share of those distributions will also increase. Under its current capital structure, each $0.01 per unit increase in distributions by the Partnership increases its total quarterly distribution by $362,000, and we would receive $281,000, or 78% of that increase.

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

• the nature of some or all of the target's assets or income might affect the Partnership's ability to be taxed as a partnership for federal income tax purposes;

• the board of directors of Crosstex Energy GP, LLC may conclude that some or all of the target assets are not a good strategic opportunity for the Partnership; or

• the seller may desire equity, rather than cash, as consideration and may not want to accept the Partnership's units as consideration.

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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

Partnership to finance all, or a portion of, such transactions, which may reduce or eliminate dividends paid to our stockholders.

CROSSTEX ENERGY, L.P.

Crosstex Energy, L.P., is a rapidly growing independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas. It connects the wells of natural gas producers in its market areas to its gathering systems, 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. It purchases natural gas from natural gas producers and other supply points and sells that natural gas to utilities, industrial consumers, other marketers and pipelines and thereby generates gross margins based on the difference between the purchase and resale prices. In addition, it purchases natural gas from producers not connected to its gathering systems for resale and sells natural gas on behalf of producers for a fee.

The Partnership's major assets include over 4,500 miles of natural gas gathering and transmission pipelines, five natural gas processing plants, and approximately 90 natural gas treating plants. Its gathering systems consist of a network of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. The Partnership's transmission pipelines primarily receive natural gas from its gathering systems and from third party gathering and transmission systems and delivers natural gas to industrial end-users, utilities and other pipelines. Its processing plants remove NGLs from a natural gas stream and fractionate, or separate, the NGLs into separate NGL products, including ethane, propane, mixed butanes and natural gasoline. Its natural gas treating plants remove impurities from natural gas prior to delivering the gas into pipelines to ensure that it meets pipeline quality specifications.

Set forth in the table below is a list of the Partnership's acquisitions since January 2000.

Acquisition	Acquisition Date	Purchase Price	Asset Type
		(In thousands)	
Provident City Plant	February 2000	$ 350	Treating plants
Will-O-Mills (50%)	February 2000	2,000	Treating plants
Arkoma Gathering System	September 2000	10,500	Gathering pipeline
Gulf Coast System	September 2000	10,632	Gathering and transmission pipeline
CCNG Acquisition	May 2001	30,003	Gathering and transmission pipeline and processing plant
Pettus Gathering System	June 2001	450	Gathering system
Millennium Gas Services	October 2001	2,124	Treating assets
Hallmark Lateral	June 2002	2,300	Pipeline segment
Pandale System	June 2002	2,156	Gathering pipeline
KCS McCaskill Pipeline	June 2002	250	Pipeline segment
Vanderbilt System	December 2002	12,000	Gathering and transmission pipeline
Will-O-Mills (50%)	December 2002	2,200	Treating plant
DEFS Acquisition	June 2003	68,124	Gathering and transmission systems and processing plants
LIG Acquisition	April 2004	73,692	Gathering and transmission systems, processing plants
Crosstex Pipeline Partners	December 2004	5,203	Gathering pipeline

The Partnership has two operating segments, Midstream and Treating. The Midstream division focuses on the gathering, processing, transmission and marketing of natural gas, as well as providing certain producer services, while the Treating division focuses on the removal of carbon dioxide and hydrogen sulfide from natural gas to meet pipeline quality specifications. See Note 15 to the consolidated financial statements for financial information about these operating segments.

References in this report to "the Partnership's predecessor" refer to Crosstex Energy Services, Ltd., a Texas limited partnership, substantially all of the assets of which were transferred to the Partnership at the closing of its initial public offering.

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

/d = per day
Btu = British thermal units
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet

Business Strategy

The Partnership's 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; improving the profitability of its 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. It will also build new assets in response to producer and market needs, such as the recently announced North Texas Pipeline project as discussed in "Recent Acquisitions and Expansion" below. We believe the expanded scope of the Partnership's operations, combined with a continued high level of drilling in its principal geographic areas, should present opportunities for continued expansion in its 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 the strategy include the following:

- *Pursuing accretive acquisitions.* The Partnership intends to use its 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. It pursues acquisitions that it believes will add to existing core areas in order to capitalize on its existing infrastructure, personnel, and producer and consumer relationships. The Partnership also examines 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. It plans 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. It established two new core areas through the acquisition of the Mississippi pipeline system in 2003 and the acquisition of the LIG pipeline system in 2004. These systems provide platforms to develop a significant presence in the south central Mississippi area and in Louisiana. Pending before the Federal Energy Regulatory Commission is the approval of abandonment from interstate service of 500 miles of interstate pipeline currently owned by Transco located in south Texas. If the abandonment is approved, the Partnership will acquire the system and two related systems, for a total of approximately $30 million.

- *Improving existing system profitability.* After the Partnership acquires or constructs a new system, it begins 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. Many recently acquired systems have excess capacity that provide opportunities to increase throughput with minimal incremental cost. As part of this process, the Partnership focuses on providing a full range of services to small and medium size independent producers and end users, including supply aggregation, transportation and hedging. Since treating services are not provided by many competitors, we have an additional advantage in competing for new supply when gas requires treating to meet pipeline specifications. Additionally, the Partnership emphasizes increasing the percentage of natural gas sales directly to end users, such as industrial and utility consumers, in an effort to increase

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

operating margins. For the year ended December 31, 2004, approximately 76% of on-system natural gas sales were to industrial end users and utilities.

- *Undertaking construction and expansion opportunities ("organic growth").* The Partnership leverages its existing infrastructure and producer and customer relationships by constructing and expanding systems to meet new or increased demand for 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. Additionally, in 2004 the Partnership significantly expanded the capacity of the Vanderbilt system from 65,000 MMBtu/d to over 100,000MMBtu/d to service one of its major customers, giving it the capacity to service their increasing needs. The Partnership also constructed nine miles of pipeline to connect an area of new production in McMullen County of south Texas to its Corpus Christi system, which provided access on a long-term basis to a significant new gas supply (65,000 MMBtu/d in the fourth quarter of 2004). It recently announced a new 122-mile pipeline construction project to move 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.

Recent Acquisitions and Expansion

LIG Pipeline Company. CELP acquired the LIG Pipeline Company and its subsidiaries from American Electric Power ("AEP") for $73.7 million on April 1, 2004. The acquisition increased the Partnership's pipeline miles by approximately 2,000 miles, to a total of 4,500 pipeline miles, and increased our average pipeline throughput by approximately 603,000 MMBtu/d for the nine months ended December 31, 2004. The acquisition also added significant processing assets to the Partnership, particularly the Placquemine and Gibson plants, which processed an average of 321,000 MMBtu/d in the fourth quarter. The acquisition was the largest in the Partnership's history.

North Texas Pipeline Project. In February 2005, CELP announced agreements to construct a 122-mile pipeline from an area near Fort Worth, Texas into new markets accessed by the NGPL pipeline system. Drilling success in the Barnett Shale formation in the area has expanded production beyond the capacity of the existing pipeline infrastructure to efficiently access markets. Capital cost to construct the pipeline and associated facilities are estimated to be approximately $98 million, with completion estimated in the first quarter of 2006.

Other Developments

Bank Credit Facility. In June 2003, the Partnership entered into a new $100.0 million senior secured credit facility, which was increased to $120 million in October 2003, consisting of a $70.0 million acquisition facility and a $50.0 million working capital and letter of credit facility. In conjunction with the LIG acquisition on April 1, 2004, the facility was increased to a total of $200 million, consisting of a $100 million acquisition facility, and a $100 million working capital and letter of credit facility.

Senior Secured Notes. In 2003, the Partnership entered into a master shelf agreement with an institutional lender pursuant to which it issued $40.0 million of senior secured notes with an interest rate of 6.93% and a maturity of seven years. In June 2004, the Partnership completed a private placement offering of $75.0 million of senior secured notes pursuant to this master shelf agreement, as amended, with an interest rate of 6.96% and a maturity of ten years. The Partnership used the net proceeds from the senior notes offerings to repay indebtedness under its bank credit facility.

Midstream Division

Gathering and Transmission. CELP's primary Midstream assets include systems located along the Texas Gulf Coast and in south-central Mississippi and in Louisiana, which, in the aggregate, consist of approximately 4,500 miles of pipeline and five processing plants and contributed approximately 77% and 73% of its gross margin in 2004 and 2003, respectively.

- *LIG System.* CELP acquired the LIG system from AEP 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, with an average throughput of approximately 603,000 MMBtu/d for the nine months ended December 31, 2004. The system also includes five processing plants with an average throughput of 294,000 MMBtu/d for the nine months ended December 31, 2004. The system has access to both rich and lean gas supplies. These supply locations range from north Louisiana to 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 Mississippi River industrial corridor between Baton Rouge and New Orleans. LIG sells the production from approximately 117 gas suppliers to approximately 58 different customers in its markets.

- *Gulf Coast System.* CELP acquired the Gulf Coast system in September 2000. It is an intrastate pipeline system consisting of approximately 515 miles of gathering and transmission pipelines with a mainline from Refugio County in south Texas running northeast along the Gulf Coast to the Brazos River in Fort Bend County near Houston. The system's gathering and transmission pipelines range in diameter from 4 to 20 inches. The Partnership recently converted a section of the Gulf Coast system to rich gas service, and added it to the Vanderbilt system (see "Vanderbilt System" below).

  The Gulf Coast system connects to gathering systems which collect natural gas from approximately 125 receipt points and has three delivery laterals which deliver natural gas directly to large industrial and utility consumers along the Gulf Coast. As of December 31, 2004, CELP was purchasing gas from over 93 producers primarily pursuant to month-to-month contracts and was reselling the natural gas to approximately 21 customers primarily pursuant to short-term or month-to-month arrangements. For the year ended December 31, 2004, approximately 89% of the natural gas volumes was purchased at a fixed price relative to an index and the remainder was purchased at a percentage of an index, and all the natural gas volumes were sold at a fixed price relative to an index. The Gulf Coast system had average throughput of approximately 72,000 MMBtu/d for the year ended December 31, 2004.

- *Vanderbilt System.* The Vanderbilt system consists of approximately 180 miles of gathering and transmission pipelines located in Wharton and Fort Bend Counties near the Gulf Coast system. CELP has converted a section of pipeline previously considered part of the Gulf Coast system into rich gas service in conjunction with the Vanderbilt system to provide additional volumes to the major customer on the system. Natural gas is supplied to the system from over 32 receipt points. Prior to our acquisition, the gas had been sold to the Exxon Katy plant. In June 2003, the Partnership reversed the flow of gas and began deliveries to a customer's large processing plant at Point Comfort, Texas. The Vanderbilt system had average throughput of approximately 68,000 MMBtu/d for the year ended December 31, 2004.

  The gas in the Vanderbilt system is now sold under a ten-year agreement, primarily from one customer, which began in June 2003 to supply up to 60,000 MMBtu/d. The agreement was modified in 2004 and again in 2005 to expand the volumes to be supplied under the agreement to 90,000 MMBtu/d. The gas is sold at a fixed price relative to an index. Gas is purchased from approximately 15 producers, primarily pursuant to month-to-month arrangements, at over 25 receipt points. Approximately 39% percent of the gas is purchased at a percentage of an index, and the remainder is purchased at a fixed price relative to an index.

- *Corpus Christi System.* The Corpus Christi system is an intrastate pipeline system consisting of approximately 355 miles of gathering and transmission pipelines and extending from supply points in south Texas to markets in the Corpus Christi area. The gathering and transmission pipelines range in diameter from four to 20 inches. The Corpus Christi system was acquired in May 2001 in conjunction with the acquisition of the Gregory gathering system and Gregory processing plant, for an aggregate purchase price of approximately $30 million.

  Natural gas is supplied to the Corpus Christi system from approximately 47 receipt points, including treating and processing plants and third-party gathering systems and pipelines. The average throughput on this system was approximately 179,000 MMBtu/d for the year ended December 31, 2004.

In June 2002, CELP acquired from Florida Gas Transmission approximately 70 miles of 20-inch transmission line which allowed CELP to access new markets within Texas and to interconnect to the Florida Gas system within Texas (the "Hallmark lateral"). CELP constructed an addition to the Hallmark lateral creating a connection between the Gulf Coast system and the Corpus Christi system. This connection allows gas transport between the two systems, thereby reducing dependence on third-party suppliers, allowing CELP to move gas supplies to more favorable markets and enhance margins. In November 2002, CELP completed construction of the interconnect between the Hallmark Lateral and the Florida Gas Transmission mainline. With this connection, CELP began selling gas into the markets served by the Florida Gas system and sold approximately 103,000 MMBtu/d for the year ended December 31, 2004.

As of December 31, 2004, the Partnership was purchasing natural gas from approximately 42 producers generally on month-to-month or short-term arrangements. For the year ended December 31, 2004, substantially all of the natural gas was purchased at a fixed price relative to an index. The Corpus Christi system transports natural gas to the Corpus Christi area where our customers include multiple major refineries and other industrial installations, as well as the local electric utility. As of December 31, 2004, gas was being sold to over 30 customers. For the year ended December 31, 2004, substantially all of the natural gas volumes were sold at a fixed price relative to an index.

- *Gregory Gathering System.* CELP acquired the Gregory processing plant and the Gregory gathering system in May 2001 in connection with the acquisition of the Corpus Christi system. The plant and the gathering system are located north of Corpus Christi, Texas. The gathering system is connected to approximately 70 receipt points in San Patricio County, the Corpus Christi Bay area, Mustang Island, and adjacent coastal areas. The gathering system consists of approximately 245 miles of pipeline ranging in diameter from two inches to 18 inches. The gathering system had average throughput of approximately 133,000 MMBtu/d for the year ended December 31, 2004 compared to an average throughput of approximately 151,000 MMBtu/d of gas per day in 2003.

  As of December 31, 2004, CELP was purchasing gas from over 48 producers primarily pursuant to month-to-month contracts, and for the year ended December 31, 2004, approximately 96% of the natural gas volumes were purchased at a fixed price relative to an index and the remainder was purchased at percentage of an index.

- *Gregory Processing Plant.* The Gregory processing plant is a cryogenic turbo expander with a 210,000 gallon per day fractionator that removes liquid hydrocarbons from the liquids-rich gas produced into the Gregory gathering system. The Gregory processing plant inlet capacity was expanded from 99,900 MMBtu/d to approximately 166,500 MMBtu/d during 2003, and average throughput was approximately 106,000 MMBtu/d for the year ended December 31, 2004. At the time of acquisition, the plant was processing approximately 43,400 MMBtu/d of gas per day.

  For the year ended December 31, 2004, CELP purchased a small amount (approximately 12%) of the natural gas volumes on its Gregory system under contracts in which CELP was exposed to the risk of loss or gain in processing the natural gas. Margins under these arrangements can be negatively affected in periods where the value of natural gas is high relative to the value of NGLs. The remaining gas purchased (approximately 88%) of the natural gas volumes on the Gregory system was purchased at a spot or market price less a discount that includes a conditioning fee for processing and marketing the natural gas and NGLs with no risk of loss or gain in processing the natural gas. Under these contracts, the producer retains ownership of the recovered NGLs, and accordingly bears the risk and retains the benefits associated with processing the natural gas.

- *Arkoma Gathering System.* CELP acquired the Arkoma gathering system, located in the Southeastern region of Oklahoma, in September 2000 for $10.5 million. The Arkoma gathering system is approximately 140 miles in length and ranges in diameter from two to 10 inches and includes 8,500 horsepower of compression from three compressor stations. This low-pressure system gathers gas from approximately 215 wells for delivery to a mainline transmission system. The Arkoma system had an average throughput of 19,000 MMBtu/d for the year ended December 31, 2004.

For the year ended December 31, 2004, CELP received a percentage of the proceeds from the sale of the natural gas to the mainline transmission pipeline for 49% of the volume on the Arkoma gathering system. Therefore, on that portion of the gas, margins were a function of the price of gas. The remaining 51% of the gas was purchased at a fixed discount to an index price. CELP takes title to the gas at the point of receipt into the gathering system, with payment based upon an allocation of the metered volume sold into the mainline transmission facilities of the customer with the producer sharing their pro rata portion of the fuel costs for the compression and the removal of water from the natural gas stream.

- *Mississippi Pipeline System.* CELP acquired the Mississippi pipeline system in June 2003. The Mississippi pipeline system is located in 15 counties of south Mississippi spanning from the city of Jackson in the northwest to Hattiesburg in the southeast. The system has wellhead supply connections in most of the gas fields in the counties of operation — primarily Jasper, Jefferson Davis, Lawrence, Marion and Simpson counties. The system delivers natural gas through direct market connections to utilities and industrial end users. The pipeline system consists of approximately 603 miles of pipeline ranging in diameter from four to 20 inches. Average throughput on this system was approximately 78,000 MMBtu/d for the year ended December 31, 2004.

  CELP purchases gas from approximately 52 producers at the delivery points into the system and sold it to approximately 23 customers. Substantially all natural gas volumes are purchased at a fixed price relative to an index.

- *Conroe Gas Plant And Gathering System.* CELP acquired the Conroe gas plant and gathering system in June 2003 in connection with the acquisition of the Mississippi pipeline system. Located in Montgomery County, Texas, the Conroe gas plant is a cryogenic gas processing plant with 10 miles of gathering pipelines located within the Conroe Field Unit, which is operated by ExxonMobil. The plant gathers low pressure and high pressure natural gas through contracts with approximately 18 producers. The plant has outlet natural gas connections to Kinder Morgan Texas Pipeline, L.P. and Copano Field Services. Recovered NGLs are delivered into the Chaparral NGL pipeline. The average throughput on this system was approximately 25,000 MMBtu/d for the year ended December 31, 2004. Operating profits at the Conroe gas plant are generated from one customer primarily from compression and processing fees and from retaining a portion of the NGLs from the recycled lift gas.

- *CPP System.* The Partnership owns five gathering systems in east Texas, totaling 64 miles. Combined average throughput on these systems was approximately 15,000 MMBtu/d for the year ended December 31, 2004.

- *Alabama Pipeline System.* The Alabama system consists of a series of three gathering and transmission systems totaling approximately 128 miles that gather gas from the traditional sandstone reservoirs on the west side of the system and coalbed methane wells on the east side of the system. Average throughput on the Alabama system was approximately 13,000 MMBtu/d for the year ended December 31, 2004.

- *Other Systems.* CELP owns several small gathering systems, including the Manziel system in Wood County, Texas, the San Augustine system in San Augustine County, Texas, the Freestone Rusk system in Freestone County, Texas, the Jack Starr and North Edna systems in Jackson County, Texas and Aurora Centana system in Louisiana. It also owns five industrial bypass systems each of which supplies natural gas directly from a pipeline to a dedicated customer. The combined volumes for these five industrial bypass systems was approximately 21,000 MMBtu/d for the year ended December 31, 2004. In addition to these systems, it owns various smaller gathering and transmission systems located in Texas, New Mexico and Louisiana.

- *Producer Services.* The Partnership is currently party to numerous transactions with approximately 41 independent producers under which it purchases and resells volumes of gas that do not move through its gathering, processing or transmission assets. This activity occurs on more than 20 interstate and intrastate pipelines with the majority being on Gulf Coast pipelines. Profits from these transactions were $2.3 million and $1.9 million for the years ending December 31, 2004 and 2003, respectively.

In addition to the business activity described above, CELP offers end users and producers the ability to hedge their purchase or sale price, provided they purchase from CELP or sell to CELP the same physical volumes of natural gas. This risk management tool enables customers to reduce pricing volatility associated with the purchase and sale of natural gas. When CELP agrees to hedge a price for a customer, it does so by simultaneously executing an offsetting physical contract for the sale or purchase of such natural gas, or enters into an offsetting obligation using futures contracts on the New York Mercantile Exchange, or by using over-the-counter derivative instruments with third parties.

Treating Division

CELP operates 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. The treating division contributed approximately 23% and 28% of the Partnership's gross margin in 2004 and 2003, respectively. The treating business has grown from 52 plants in operation at December 31, 2003 to 74 plants in operation at December 31, 2004.

As of December 31, 2004, the Partnership owned 90 treating plants, 60 of which were operated by its personnel, 14 of which were operated by producers, and 16 of which were held in inventory. CELP entered the treating business in 1998 with the acquisition of WRA Gas Services and it now has one of the largest gas treating operations in the Texas 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. The majority of the 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 CELP to operate the treating facilities, it either charges a fixed rate per Mcf of natural gas treated or charges a fixed monthly fee.

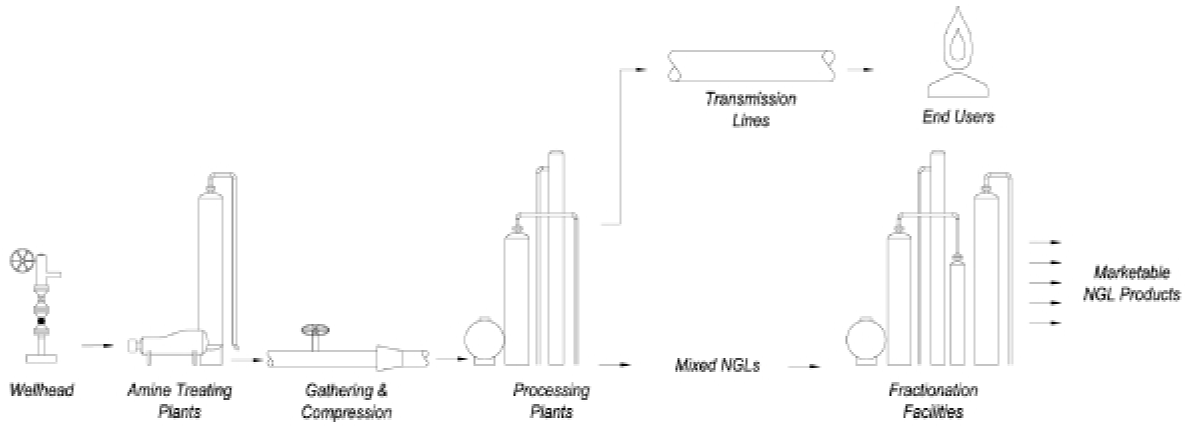
CELP also owns an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas, and which is accounted for as part of the Treating Division. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon 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.

The Partnership's treating growth strategy is based on the belief that if gas prices remain high it will encourage drilling deeper gas formations. It believes 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. CELP believes its track record of reliability, current availability of equipment, and its strategy of sourcing new equipment gives it 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 absorb the impurities from the gas. After mixing, gas and 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. 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 in the Texas Gulf Coast 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 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. Most natural gas produced by a well is not 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, plant tailgates, and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

Risk Management

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

Competition

The business of providing natural gas gathering, transmission, treating, processing and marketing services is highly competitive. CELP faces strong competition in acquiring new natural gas supplies. Its competitors in obtaining additional gas supplies and in treating new natural gas supplies include major integrated oil companies, major interstate and intrastate pipelines, and other natural gas gatherers that gather, process and market natural gas. Competition for natural gas supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. Many of its competitors have substantially greater capital resources and control substantially greater supplies of natural gas. Competition will likely differ in different geographic areas.

The gas treating operations face competition from manufacturers of new treating plants and from a small number of regional operators that provide plants and operations similar to the Partnership. It also faces competition from vendors of used equipment that occasionally operate plants for producers.

In marketing natural gas, CELP has 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 CELP.

Natural Gas Supply

CELP's transmission 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 gathering systems, CELP evaluates 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 the investment. Based on these facts, CELP believes that there should be adequate natural gas supply to recoup the investment with an adequate rate of return. It does not routinely obtain independent evaluations of reserves dedicated to its systems due to the cost of such evaluations. Accordingly, it does not have estimates of total reserves dedicated to its systems or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

CELP is diligent in attempting to ensure that we issue credit to only credit-worthy customers. However, the purchase and resale of gas exposes CELP 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 CELP's overall profitability.

During the year ended December 31, 2004, we had one customer that individually accounted for more than 10% of consolidated revenues. During the year ended December 31, 2004, Kinder Morgan Tejas accounted for 10.2% of our consolidated revenue. 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. CELP does not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission ("FERC") does not directly regulate any of its

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

operations. However, FERC's regulation influences certain aspects of its business and the market for its products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- maximum rates payable for certain services;
- 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. Pending before the FERC is a proposal to abandon a 500 mile section of the Transco interstate system, which if approved, would allow CELP to acquire that system as a deregulated asset and put it into intrastate service.

Intrastate Pipeline Regulation. CELP's 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. However, to the extent that CELP's intrastate pipeline systems transport natural gas in interstate commerce, the rates, terms and conditions of such transportation services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGA"). Section 311 regulates, among other things, the providing of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. 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.

The Partnership's 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 charged 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 CELP or whether the TRRC will change its regulation of these rates.

CELP owns 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 the Mississippi gathering system is regulated by the Mississippi Oil and Gas Board as it transports gas for a fee. The Arkoma Gathering System in Oklahoma is regulated by the Oklahoma Corporation Commission. Similarly, gathering systems in Alabama are subject to regulation by the Alabama State Oil and Gas Board. The 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. CELP owns 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 its gathering facilities are subject to change based on future determinations by FERC and the courts. State

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

CELP is 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 CELP's right as an owner of gathering facilities to decide with whom it contracts 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. CELP's 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. CELP's gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on CELP's 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 CELP sells natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. 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 CELP's 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 CELP will be affected by any such FERC action materially differently than other natural gas marketers with whom CELP competes.

Environmental Matters

General. CELP's operation of processing and fractionation plants, pipelines and associated facilities in connection with the gathering and processing of natural gas and the transportation, fractionation and storage of NGLs is subject to stringent and complex federal, state and local laws and regulations relating to release of hazardous substances or wastes into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases CELP's 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 CELP currently holds material governmental approvals required to operate its major facilities, it is currently evaluating and updating permits for certain facilities that primarily were obtained in recent acquisitions. As part of the regular overall evaluation of its operations, CELP has implemented procedures to ensure that all governmental approvals, for both recently acquired facilities and existing operations are updated, as may be necessary. We believe that CELP's operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on 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 CELP's possible future operations, and we cannot assure you that it 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, it 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 it 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. CELP will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly in order to remain in compliance with changing environmental laws and regulations and in order to minimize the costs of such compliance.

Hazardous Substance and Waste. To a large extent, the environmental laws and regulations affecting the Partnership's 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, CELP may generate wastes that may fall within the definition of a "hazardous substance." CELP may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed. CELP has not received any notification that it may be potentially responsible for cleanup costs under CERCLA or any analogous state laws.

CELP also generates, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. 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. CELP is not currently required to comply with a substantial portion of the RCRA requirements because its operations generate minimal quantities of hazardous wastes. However, it is possible that some wastes generated that are currently classified as nonhazardous may in the future be designated as "hazardous wastes,"

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

resulting in the wastes being subject to more rigorous and costly disposal requirements. Changes in applicable regulations may result in an increase in capital expenditures or plant operating expenses.

CELP currently owns or leases, and has in the past owned or leased, and in the future may own or lease, properties that have been used over the years for natural gas gathering and processing and for NGL fractionation, transportation and 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 CELP during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom CELP 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.

CELP acquired two assets from Duke Energy Field Services, L.P. ("DEFS") in June 2003 that have environmental contamination. These two assets were a gas plant in Montgomery County near Conroe, Texas and a compressor station near Cadeville, Louisiana. At both of these sites, 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 and the remediation cost for the Cadeville site is currently estimated to be approximately $1.2 million. Under the purchase and sale agreement, DEFS retained the liability for cleanup of both the Conroe and Cadeville sites. 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. In addition, effective September 1, 2004, CELP sold its Cadeville assets, including the compressor station and gathering system, subject to the retained DEFS indemnity, to a third party. Therefore, the Company does not expect to incur any material environmental liability associated with the Conroe or Cadeville sites.

CELP acquired LIG Pipeline Company, and its subsidiaries, on April 1, 2004 from AEP. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. AEP has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third-party company pursuant to which the remediation costs associated with these sites have been assumed by this third-party company that specializes in remediation work. The Company does not expect to incur any material liability with these sites. In addition, CELP has disclosed possible Clean Air Act monitoring deficiencies it has discovered to the Louisiana Department of Environmental Quality and is working with the department to correct these deficiencies and to address modifications to facilities to bring them into compliance. The Company does not expect to incur any material environmental liability associated with these issues.

Air Emissions. CELP's operations are, and its 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, CELP's processing and fractionating plants, pipelines, and storage facilities or any of its 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 operations, could cause it 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 its facilities and which may apply to some of its 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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

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 CELP is in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

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

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered species or their habitats. Presently, the Partnership operates in only one area that is designated as a critical habitat for a certain species of beetle. This area consists of 29 counties in eastern and central Oklahoma into which part of CELP’s gathering system extends. A coalition of oil and gas industry and regulatory agencies are currently working together to minimize impacts on future construction and operation activities for oil and gas production and transportation. This designated area has had no material effect on the Partnership’s operations in Oklahoma to date. While we have no reason to believe that CELP operates in any other area that is currently designed as habitat for endangered or threatened species, the discovery of previously unidentified endangered species could cause CELP to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Safety Regulations. The Partnership’s pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, as amended, or HLPSA, and the Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192, effective February 14, 2004 relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA covers crude oil, carbon dioxide, NGL and petroleum products pipelines and requires any entity which owns or operates pipeline facilities to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. The Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192 (PIM) requires operators of gas transmission pipelines and segments of gathering lines in certain populated areas 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. We believe that the Partnership’s 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.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

Office Facilities

In addition to the gathering and treating facilities discussed above, the Partnership occupies approximately 65,000 square feet of space at our executive offices in Dallas, Texas under a lease expiring in March 2010.

Employees

As of December 31, 2004, the Partnership had approximately 325 full-time employees. Approximately 147 of the employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. CELP is not party to any collective bargaining agreements, and has not had any significant labor disputes in the past. We believe that CELP has good relations with its employees.

Item 2. *Properties*

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

Title to Properties

Substantially all of the Partnership's pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. CELP has obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which the Partnership's pipeline was built was purchased in fee. The Gregory processing plant is on land that it owns in fee.

We believe that CELP has satisfactory title to all of its rights of way and land assets. Title to these assets may be subject to encumbrances. We believe that none of such encumbrances should materially detract from the value of the assets or from the Partnership's interest in these assets or should materially interfere with their use in the operation of the business.

Item 3. *Legal Proceedings*

The Partnership's operations are subject to a variety of risks and disputes normally incident to the business. As a result, at any given time it may be a defendant in various legal proceedings and litigation arising in the ordinary course of business. It maintains insurance policies with insurers in amounts and with coverage and deductibles as the managing general partner believes are reasonable and prudent. However, we cannot assure that this insurance will be adequate to protect the Partnership from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

In May 2003, four landowner groups filed suit against CELP in the 267th Judicial District Court in Victoria County, Texas seeking damages related to the expiration of an easement for a segment of one of its pipelines located in Victoria County, Texas. In 1963, the original owners of the land granted an easement for a term of 35 years, and the prior owner of the pipeline failed to renew the easement. CELP filed a condemnation counterclaim in the district court suit and it filed, in a separate action in the county court, a condemnation suit seeking to condemn a 1.38-mile long easement across the land. Pursuant to condemnation procedures under the Texas Property Code, three special commissioners were appointed to hold a hearing to determine the amount of the landowner's damages. In August 2004, a hearing was held and the special commissioners awarded damages to the four current landowner groups in the amount of $877,500. CELP has timely objected to the award of the special commissioners and the condemnation case will now be tried in the county court on May 9, 2005. The damages award by the special commissioners will have no effect and cannot be introduced as evidence in the county court. The county court will determine the amount that CELP will pay the current landowners for an easement across their land and will determine whether or not and to what extent the current landowner groups are entitled to recover any damages for the time period that there was not an easement for the pipeline on their land. Under the Texas Property Code, in order to maintain possession of and continued use of the pipeline until the matter has been resolved in the county court, CELP was required to post bonds and cash, each totaling the amount of $877,500, which is the amount of the special commissioners award. We are not able to predict the ultimate outcome of this matter.

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, 2004.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

PART II

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

Our common stock is listed on the NASDAQ National Market under the symbol "XTXI." Our common stock began trading on January 12, 2004. Before that date, there was no public market for shares of our common stock. On February 25, 2005, the market price for our common stock was $41.81 per share and there were approximately 2,636 record holders and beneficial owners (held in street name) of the shares of our common stock.

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

	Common Stock Price Range		
2004:	**High**	**Low**	**Cash Dividends Paid Per Share**
Quarter Ended December 31	44.09	39.11	$ 0.39
Quarter Ended September 30	41.38	36.24	0.35
Quarter Ended June 30	43.98	38.85	0.33
Quarter Ended March 31	42.00	25.00	0.30

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

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

If the Partnership continues to be successful in implementing its business strategy and increasing distributions to its partners, we would expect to continue to increase dividends to our stockholders, although the timing and amount of any such increased dividends will not necessarily be comparable to the increased Partnership distributions.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors deems relevant. The Partnership's debt agreements contain restrictions on the payment of distributions and prohibit the payment of distributions if the Partnership is in default. If the Partnership cannot make incentive distributions to the general partner or limited partner distributions to us, we will be unable to pay dividends on our common stock.

Use of Proceeds from Registered Securities

On January 12, 2004, our registration statement on Form S-1 (Registration No. 333-110095) was declared effective by the Securities and Exchange Commission in connection with the initial public offering of shares of our common stock. The net proceeds that we received from the initial public offering of the shares of common stock was approximately $4.8 million. We plan to use the net proceeds received by us from the initial public offering for general corporate expenses, but have not done so as of the date of this report.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

Item 6. *Selected Financial Data*

The following table sets forth selected historical financial and operating data of Crosstex Energy, Inc. and our predecessor, Crosstex Energy Services, Ltd., as of and for the dates and periods indicated. The selected historical financial data are derived from the audited financial statements of Crosstex Energy, Inc. or our predecessor, Crosstex Energy Services, Ltd. The investment in our predecessor by Yorktown Energy Partners IV, L.P. in May 2000 resulted in the dissolution of the predecessor partnership and the creation of a new partnership with the same organization, purpose, assets, and liabilities. Accordingly, the financial statements of our predecessor for 2000 are divided into the four months ended April 30, 2000 and the eight months ended December 31, 2000 because a new basis of accounting was established effective May 1, 2000 to give effect to the Yorktown transaction. In addition, our summary historical financial and operating include the results of operations of the Arkoma system beginning in September 2000, the Gulf Coast system beginning in September 2000, 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 the Seminole processing plant beginning in June 2003, and the LIG assets beginning in April 2004.

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

	Crosstex Energy, Inc.					Crosstex Energy Services, Ltd.(1)
	Year Ended December 31, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001	Eight Months Ended December 31, 2000	Four Months Ended April 30, 2000
	(Dollars in thousands, except per share amounts)					
Statement of Operations Data:						
Revenues:						
Midstream	$ 1,948,021	$ 989,697	$ 437,432	$ 362,673	$ 88,008	$ 3,591
Treating	30,775	23,966	14,817	24,353	17,392	5,947
Total revenues	1,978,776	1,013,663	452,249	387,026	105,400	9,538
Operating costs and expenses:						
Midstream purchased gas	1,861,204	946,412	414,244	344,755	83,672	2,746
Treating purchased gas	5,274	7,568	5,767	18,078	14,876	4,731
Operating expenses	38,197	17,758	11,420	7,761	1,796	544
General and administrative	21,175	11,593	7,663	5,583	2,010	810
Stock based compensation	1,029	5,345	41	—	—	8,802
Impairments	981	—	4,175	2,873	—	—
(Profit) loss on energy trading contracts	(2,507)	(1,905)	(1,657)	3,714	(1,253)	(638)
Gain on sale of property	(12)	—	—	—	—	—
Depreciation and amortization	23,034	13,542	7,745	6,208	2,333	522
Total operating costs and expenses	1,948,201	1,000,313	449,398	388,972	103,434	17,517
Operating income (loss)	30,401	13,350	2,851	(1,946)	1,966	(7,979)

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

	Crosstex Energy, Inc.					Crosstex Energy Services, Ltd.(1)
	Year Ended December 31, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001	Eight Months Ended December 31, 2000	Four Months Ended April 30, 2000
	(Dollars in thousands, except per share amounts)					
Other income (expense):						
Interest expense, net	(9,115)	(3,103)	(2,381)	(2,253)	(530)	(79)
Other income (expense)	803	179	52	174	115	381
Total other income (expense)	(8,312)	(2,924)	(2,433)	(2,079)	(415)	302
Income (loss) before gain on issuance of units by the partnership, income taxes and interest of non-controlling partners in the partnership's net income	22,088	10,426	418	(4,025)	1,551	(7,677)
Gain on issuance of partnership units(2)		18,360	11,781	—	—	—
Income tax (provision) benefit	(5,149)	(10,157)	(6,871)	1,294	(679)	—
Interest of non-controlling partners in the partnership's net income	(8,239)	(5,181)	(99)	—	—	—
Net income (loss)	$ 8,700	$ 13,448	$ 5,229	$ (3,918)	$ 872	$ (7,677)
Net income (loss) per common share — basic(3)	$ 0.72	$ 2.83	$ 0.59	$ (1.25)	$ 0.05	N/A
Net income (loss) per common share — diluted(3)	$ 0.67	$ 1.10	$ 0.46	$ (1.25)	$ 0.05	N/A
Balance Sheet Data:						
Working capital surplus (deficit)	$ (18,265)	$ (7,705)	$ (11,141)	$ (1,555)	$ 5,763	$ (4,005)
Property and equipment, net	325,653	104,890	111,203	84,951	37,242	10,540
Total assets	606,768	370,485	241,424	171,369	202,909	45,051
Long-term debt	148,700	60,750	22,550	60,000	22,000	7,000
Interest of non-controlling partners in the partnership	65,399	67,157	26,815	—	—	—
Stockholders' equity	76,933	69,266	57,397	42,241	39,808	3,608
Cash Flow Data:						
Net cash flow provided by (used in):						
Operating activities	$ 46,339	$ 42,103	$ (5,050)	$ (10,686)	$ 7,634	$ 7,380
Investing activities	(124,371)	(110,288)	(33,240)	(52,535)	(25,643)	(2,849)
Financing activities	99,072	65,856	41,746	44,918	36,664	198

	Crosstex Energy, Inc.					Crosstex Energy Services, Ltd.(1)
	Year Ended December 31, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001	Eight Months Ended December 31, 2000	Four Months Ended April 30, 2000
	(Dollars in thousands, except per share amounts)					
Other Financial Data:						
Midstream gross margin	$ 86,817	$ 43,285	$ 23,188	$ 17,918	$ 4,336	$ 845
Treating gross margin	25,481	16,398	9,050	6,275	2,516	1,216
Total gross margin(4)	$ 112,298	$ 59,683	$ 32,238	$ 24,193	$ 6,852	$ 2,061
Operating Data:						
Pipeline throughput (MMBtu/d)	1,289,000	626,000	392,000	313,000	104,000	23,000
Natural gas processed (MMBtu/d)	425,000	132,000	86,000	61,000	16,000	31,000

(1) We, through our ownership interest in the Partnership, are the successor to Crosstex Energy Services, Ltd. Results of operations and balance sheet data prior to May 1, 2000 represent historical results of the predecessor to Crosstex Energy Services, Ltd. These results are not necessarily comparable to the results of Crosstex Energy Services, Ltd. subsequent to May 2000 due to the new basis of accounting. There are no income tax provisions for these predecessor periods because Crosstex Energy Services, Ltd. was a limited partnership not subject to federal income taxes.

(2) We recognized gains of $11.8 million in 2002 and $18.4 million in 2003 as a result of the Partnership issuing additional units to the public in public offering at prices per unit greater than our equivalent carrying value.

(3) Per share amounts have been adjusted for the two-for-one stock split made in conjunction with our initial public offering in January 2004.

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

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

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

Overview

Crosstex Energy, Inc. is a Delaware corporation formed on April 28, 2000 to engage through its subsidiaries in the gathering, transmission, treating, processing and marketing of natural gas. On July 12, 2002, we formed Crosstex Energy, L.P., a Delaware limited partnership, to acquire indirectly substantially all of the assets, liabilities and operations of its predecessor, Crosstex Energy Services, Ltd. Our assets consist almost exclusively of partnership interests in Crosstex Energy, L.P., a publicly traded limited partnership engaged in the gathering, transmission, treating, processing and marketing of natural gas. These partnership interests consist of (i) 666,000 common units and 9,334,000 subordinated units, representing approximately 54% of the limited partner interests in Crosstex Energy, L.P. and (ii) 100% ownership interest in Crosstex Energy GP, L.P., the general partner of Crosstex Energy, L.P., which owns a 2.0% general partner interest and all of the incentive distribution rights in Crosstex Energy, L.P.

Our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. The Partnership is required by its partnership agreement to distribute all its cash on hand at

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership's business or to provide for future distributions.

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

Distributions by the Partnership have increased from $0.25 per unit for the quarter ended March 31, 2003 (its first full quarter of operation after its initial public offering), to $0.45 per unit for the quarter ended December 31, 2004. As a result, our distributions from the Partnership pursuant to our ownership of our 10,000,000 common and subordinated units have increased from $2,500,000 per quarter to $4,500,000 per quarter; our distributions pursuant to our 2% general partner interest has increased from $74,000 to $203,000; and our distributions pursuant to our incentive distribution rights have increased from nothing to $1,822,000 per quarter. As a result, we have increased our dividend from $0.30 per share for the quarter ended March 31, 2004 (the first dividend payout after our initial public offering) to $0.39 per share for the quarter ended December 31, 2004.

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

The Partnership has two industry segments, Midstream and Treating, with a geographic focus along the Gulf Coast of the United States. The Partnership's Midstream division focuses on the gathering, processing, transmission and marketing of natural gas, as well as providing certain producer services, while the Treating division focuses on the removal of carbon dioxide and hydrogen sulfide from natural gas to meet pipeline quality specifications. For the year ended December 31, 2004, 77% of our gross margin was generated in the Midstream division, with the balance in the Treating division. CELP focuses on gross margin to manage its business because its business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas for a fee. CELP buys and sells most of its gas at a fixed relationship to the relevant index price so margins are not significantly affected by changes in gas prices. As explained under "Commodity Price Risk" below, it enters into financial instruments to reduce volatility in gross margin due to price fluctuations.

Since the Partnership's formation, it has grown significantly as a result of construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2000 through December 31, 2004, it has invested over $300 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.

The Partnership's results of operations are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through its pipeline systems, processed at its processing facilities or treated at its treating plants as well as fees earned from recovering carbon dioxide and natural gas liquids at a non-operated processing plant. It generates revenues from five primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems it owns;
- processing natural gas at its processing plants;
- treating natural gas at its treating plants;
- recovering carbon dioxide and natural gas liquids at a non-operated processing plant; and
- providing producer services.

The bulk of the Partnership's operating profits are derived from the margins it realizes for purchasing and reselling natural gas through its pipeline systems. Generally, the Partnership buys gas from a producer, plant tailgate, or transporter at either a fixed discount to a market index or a percentage of the market index. The Partnership then transports and resells the gas. The resale price is based on the same index price at which the gas was purchased, and, if the Partnership is to be profitable, at a smaller discount or larger premium to the index than it was purchased. The Partnership attempts to execute all purchases and sales substantially concurrently, or it enters into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. The Partnership's 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 it manages its business to reduce the impact of price volatility.

The Partnership generates producer services revenues through the purchase and resale of natural gas. The Partnership currently purchases for resale volumes of natural gas that do not move through its gathering, processing or transmission assets from over 41 independent producers. The Partnership engages in such activities on more than 20 interstate and intrastate pipelines with a major emphasis on Gulf Coast pipelines. The Partnership focuses on supply aggregation transactions in which it either purchases and resells gas and thereby eliminates the need of the producer to engage in the marketing activities typically handled by in-house marketing or supply departments of larger companies, or act as agent for the producer.

The Partnership generates treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 53% and 55% of the operating income in the Treating division for the years ended December 31, 2004 and 2003, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 43% and 38% of the operating income in the Treating division for the years ended December 31, 2004 and 2003, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 4% and 7% of the operating income in the Treating division for the years ended December 31, 2004 and 2003, 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.

We modified certain terms of certain outstanding options on our common stock 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. We were 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 $5.0 million related to these modified options in 2003.

The Partnership has 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 1, 2002, are the acquisitions of the Vanderbilt system, DEFS assets, and LIG assets.

The Partnership acquired the Vanderbilt system in December 2002 for a purchase price of $12.0 million. The Vanderbilt system consists of approximately 200 miles of gathering lines in the same approximate geographic area as the Gulf Coast System. At the time of its acquisition, it was transporting approximately 32,000 MMBtu of gas per day.

The Partnership 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. The acquisition provided CELP with a new core area for growth in south central Mississippi, expanded its presence in West Texas and enabled it to enter the business of carbon dioxide separation.

In April 2004 the Partnership acquired LIG Pipeline Company and its subsidiaries (collectively, “LIG”) from a subsidiary of American Electric Power (“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, three of which are currently idle, that straddle the pipeline in three locations and have a total processing capability of 663,000 MMbtu/d. The system has a throughput 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. The LIG acquisition was financed through borrowings under the bank credit facility.

Other Assets. We own two inactive gas plants and a receivable associated with the Enron Corp. bankruptcy in addition to our limited and general partner interests in the Partnership. The two gas plants are the Jonesville processing plant, which had been largely inactive since the beginning of 2001, and the Clarkson plant, acquired shortly before the Partnership’s initial public offering. In the third quarter of 2004, we fully impaired our investment in the Jonesville plant.

Impact of Federal Income Taxes. Crosstex Energy, Inc. is a corporation for federal income tax purposes. As such, our federal taxable income is subject to tax at a maximum rate of 35.0% under current law. We expect to have significant amounts of taxable income allocated to us as a result of our investment in the Partnership units particularly because of remedial allocations that will be made among the unitholders and because of the general partner’s incentive distribution rights, which we will benefit from as the sole owner of the general partner. Taxable income allocated to us by the Partnership will increase over the years as the ratio of income to distributions increases for all of the unitholders.

We currently have a net operating loss carryforward, and estimate that we will generate a net operating loss in fiscal 2004. We estimate that our net operating loss carryforward and our share of deductions related to the exercise of our stock options prior to their expiration in 2005 will offset most of the income that will be allocated to us in fiscal 2005 by the Partnership. In years after 2005, however, we do not expect to have this net operating loss carryforward to offset our income. As a result, we will have to pay tax on our federal taxable income at a maximum rate of 35.0% under current law. Thus, the amount of money available to make cash distributions to our stock holders will decrease markedly after we use all of our net operating loss carryforward.

Our use of this net operating loss carryforward will be limited if there is a greater than 50.0% change in our stock ownership over a three year period. However, we do not expect such a change in ownership to limit our utilization of carryforwards prior to their 20-year expiration period.

Commodity Price Risk

The Partnership's 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 NGL products and natural gas market uncertainty.

Profitability under the Partnership's 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 the Partnership buys 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 the Partnership's principal gathering and transmission systems and for its producer services business for the year ended December 31, 2004.

	Year Ended December 31, 2004			
	Gas Purchased		Gas Sold	
Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(In thousands of MMBtus)			
Gulf Coast system	22.4	2.7	25.1	—
CCNG transmission system	75.9	5.2	81.1	—
Gregory gathering system(1)	46.9	1.8	35.4	—
Vanderbilt system(1)	20.2	13.0	30.0	—
Conroe system(1)	0.5	0.6	0.8	—
Arkoma gathering system	3.5	3.4	6.9	—
Mississippi system	28.2	0.4	28.6	—
LIG system	96.4	5.2	101.6	—
Producer services(2)	76.4	0.4	76.8	—

(1) Gas sold is less than gas purchased due to production of natural gas liquids.

(2) These volumes are not reflected in revenues or purchased gas cost, but are presented net as a component of profit (loss) on energy trading activities.

The Partnership estimates that, due to the gas that it purchases at a percentage of index price, for each $0.50 per MMBtu increase or decrease in the price of natural gas, its gross margins increase or decrease by approximately $1.6 million on an annual basis (before consideration of the hedges discussed below). As of

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

December 31, 2004, it has hedged approximately 58% of its exposure to such fluctuations in natural gas prices as follows for future periods:

Period	Volume Hedged (MMBtu per month)	Weighted-Average Price per MMBtu
First quarter of 2005	180,000	$ 6.074
Second quarter of 2005	180,000	$ 6.074
Third quarter of 2005	120,000	$ 5.851
Fourth quarter of 2005	120,000	$ 5.851

The Partnership expects to continue to hedge its exposure to gas production which it purchases at a percentage of index when market opportunities appear attractive.

The Partnership's processing plants at Plaquemine and Gibson have a variety of processing contract structures. In general, the Partnership buys gas under keep-whole arrangements in which it bears the risk of processing, percentage-of-proceeds arrangements in which it receives 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 the Partnership has the ability to bypass certain volumes when processing is uneconomic, it can limit its exposure to adverse processing margins. During periods when processing margins are favorable, the Partnership can substantially increase the volumes it is processing, as was the case in the fourth quarter of 2004.

For the year ended December 31, 2004, the Partnership purchased a small amount (approximately 4%) of the natural gas volumes on its Gregory system under contracts in which it was exposed to the risk of loss or gain in processing the natural gas. The Partnership purchased the remaining approximately 96% of the natural gas volumes on its Gregory system 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 its Gregory processing plant with no risk of loss or gain in processing the natural gas.

The Partnership's Conroe gas plant and gathering system generates revenues based on fees it charges to producers for gathering and compression services, and it retains 40% of the NGLs produced from a portion of the gas processed at the facility.

The Partnership owns 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, the Partnership has commodity price exposure due to variances in the prices of NGLs. During 2004, our share of NGLs totaled 5,891,248 gallons at an average price of $0.72 per gallon.

Gas prices can also affect the Partnership's 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.

	Year Ended December 31, 2004	2003	2002
		(dollars in millions)	
Midstream revenues	$ 1,948.0	$ 989.7	$ 437.4
Midstream purchased gas	1,861.2	946.4	414.2
Midstream gross margin	86.8	43.3	23.2
Treating revenues	30.8	24.0	14.8
Treating purchased gas	5.3	7.6	5.8
Treating gross margin	25.5	16.4	9.0
Total gross margin	$ 112.3	$ 59.7	$ 32.2
Midstream Volumes (MMBtu/d):			
Gathering and transportation	1,289,000	626,000	392,000
Processing	429,000	132,000	86,000
Producer services	210,000	259,000	230,000
Treating Plants in Operation at Year End	74	52	35

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 acquired 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 than expected processing margins and volumes from existing gas operations, which increased margins $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 interest 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 $38.0 million for the year ended December 31, 2004 compared to $17.7 million for the year ended December 31, 2003, an increase of $20.3 million, or 115%. Increases of $3.5 million and $9.4 million were associated with the acquisition of the DEFS and LIG assets, respectively. General operations expense (expense not directly related to specific assets) was $6.0 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.

General and Administrative Expenses. General and administrative expenses were $21.2 million for the year ended December 31, 2004, compared to $11.6 million for the year ended December 31, 2003, an increase of $9.6 million, or 83%. A significant contributor was additional staffing-related costs, an incremental $5.0 million over 2003. The staff additions required to manage and optimize the 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 systems, providing a more scalable infrastructure. Sarbanes Oxley compliance costs are $1.1 million for 2004, compared to zero for 2003. A $0.6 million increase due to unsuccessful transaction costs was a result of, among other things, the size of the acquisitions pursued. Other expenses, including audit and tax fees, office rent, K-1 preparation fees and travel expenses, accounted for $1.1 million of the increase.

Stock-Based Compensation. Stock-based compensation expense decreased from $5.3 million for the year ended December 31, 2003 to $1.0 million for the year ended December 31, 2004. During 2003, certain of our outstanding 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 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.

Impairment. An impairment of $981,000 was recognized during 2004 related to a processing plant that is owned directly by us. This plant has been inactive since late 2002 when the operator of the wells behind the plant cancelled its drilling plans for the area. An impairment on the contracts associated with the plant was recorded in 2002 but the value of the plant was not impaired because we intended to restart or relocate the plant. Drilling activity has increased in the area near the plant and processing margins have improved during 2004 so management decided to more fully evaluate the cost of restarting this idle plant. Management determined that it would be more commercially feasible to put a new plant at the plant site than to invest the capital necessary to restart the plant. If we do not restart the plant, our engineers estimate that the plant would receive very little, if any, value upon the sale of the plant. Therefore, we have impaired the full value of the plant during 2004.

(Profit) Loss on Energy Trading Activities. The profit on energy trading activities was $2.5 million for the year ended December 31, 2004 compared to $1.9 million for the year ended December 31, 2003. Included in these amounts are realized margins on delivered volumes in the producer services “off-system” gas marketing operations of $2.3 million and $2.2 million for the years ended December 30, 2004 and 2003, respectively.

Gain on Sale of Property. During 2004, the Partnership sold two small gathering systems and recognized a net gain on sale of $12,000.

Depreciation and Amortization. Depreciation and amortization expenses were $23.0 million for the year ended December 31, 2004 compared to $13.5 million for the year ended December 31, 2003, an increase of $9.5 million, or 70%. 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 increase in depreciation and amortization is primarily 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 $9.1 million for the year ended December 31, 2004 compared to $3.1 million for the year ended December 31, 2003, an increase of $6.0 million, or 194%. The increase relates primarily to an increase in average debt outstanding. Average higher 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 $802,000 for the year ended December 31, 2004 compared to $179,000 for the year ended December 31, 2003. Other income in 2004 includes the write-off of $167,000 related to an environmental liability accrued in connection with the June 2003 acquisition of properties from DEFS which was in excess of amounts spent to resolve the environmental matters identified at the time of acquisition. In addition, other income in 2004 includes $277,000 related to a reimbursement for a construction project in excess of our costs for such project.

Income Tax Expense. We provide for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. Our income tax provision was $5.1 million in 2004 compared to $10.2 million in 2003, a decrease of $5.0 million. The decrease in the tax provision was primarily due to the taxes provided on the $18.4 million gain on issuance of units of the Partnership during 2003 partially offset by taxes provided on higher operating income in 2004. We estimate that we will generate a net operating loss in 2004. The current tax provision of approximately $347,000 represents current taxes related to the Partnership's wholly owned corporate LIG subsidiaries.

Interest of Non-controlling Partners in the Partnership's Net Income. We recorded an expense of $8.2 million in 2004 and $5.2 million in 2003 associated with the interests of non-controlling partners in the Partnership. This expense increased between periods because the Partnership's net income increased by $8.5 million from 2003 to 2004 and the non-controlling partners' ownership in the Partnership increased from 31.5% to 43.8% in September 2003 as a result of the issuance of additional common units to the public shareholders. The increases related to Partnership net income and non-controlling partner ownership were partially offset by the impact of incentive distributions increasing from $954,000 for the year ended December 31, 2003 to $5,550,000 for the year ended December 31, 2004. Income from the Partnership is allocated to us for its incentive distributions with the remaining income being allocated pro rata to the 2% general partner interest and the common unit and subordinated units.

Net Income. Net income for the year ended December 31, 2004 was $8.7 million compared to $13.4 million for the year ended December 31, 2003, a decrease of $4.7 million. Net income decreased from 2003 to 2004 primarily due to the gain on sale of issuance of units of the Partnership in 2003 of $18.4 million and an increase in the expenses for the non-controlling partners' share of Partnership net income of $3.1 million, partially offset by an increase of $17.1 million in operating income and a decrease of $5.0 million in the income tax provision.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Gross Margin. Midstream gross margin was $43.4 million for the year ended December 31, 2003 compared to $23.2 million for the year ended December 31, 2002, an increase of $20.2 million, or 87%. The largest increase in gross margin was due to the acquisition of assets from DEFS on June 30, 2003. These assets added gross margin of $6.0 million. The Corpus Christi system had significant growth due to an increase in on-system volume and the addition of the Hallmark lateral, resulting in an increase in margin of $4.7 million. We acquired the Vanderbilt Gathering system on December 31, 2002; this system added gross margin of $4.4 million. Gregory gathering system and Gregory processing plant had increased margin of $2.6 million. These systems had significant growth in volume due to producer drilling activity in the area, to which the Partnership responded with the Gregory plant expansion during 2003. The Gulf Coast system had increased margin of $1.2 million despite the fact that volumes declined. The reason for the decline in volume was because we sourced two markets from Vanderbilt the last half of 2003 that were previously sourced from the Gulf Coast system. We had an increase in volume and increase in margin due to a large customer taking gas from our system for 12 months in 2003 and only six months in 2002, and we had increased margin due to renegotiation of producer contracts. The Arkoma system also had increased volume, creating an increase in margin of $0.8 million.

Treating gross margin was $16.4 million for the year ended December 31, 2003 compared to $9.0 million in the same period in 2002, an increase of $7.4 million, or 82%. Seminole asset acquired from DEFS accounted for $3.4 million of the increase. The remaining increase was due to 27 new plants placed in service in 2003, which generated $3.7 million offset by 10 plants removed from service in 2003, which decreased margin by $0.8 million (a net increase of $2.9 million). In addition, an increase in volume at two plants with throughput-based contracts accounted for $1.1 million of the increase in treating margin.

Operating Expenses. Operating expenses were $17.8 million for the year ended December 31, 2003, compared to $11.4 million for the year ended December 31, 2002, an increase of $6.4 million, or 56%. An increase of $3.1 million was associated with the acquisition of assets from DEFS in June 2003. Costs for the Partnership's technical services support increased by approximately $0.8 million due to staff additions to operate the assets acquired in December 2002 and in June 2003 from DEFS and to manage other construction projects. The Vanderbilt system added $1.1 million to operating expenses, new treating plants increased operating expenses by $0.6 million and the Gregory Plant expansion added $0.4 million in operating expenses.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

General and Administrative Expenses. General and administrative expenses were $11.6 million for the year ended December 31, 2003 compared to $7.7 million for the year ended December 31, 2002, an increase of $3.9 million, or 51%. The increase was primarily due to increases in staffing associated with the requirements of the DEFS acquisition and associated with the Partnership being a public entity. We also recognized an additional bad debt reserve of $1.2 million related to the Company's Enron receivable based on current recovery estimates from Enron's bankruptcy proceedings.

Impairments. The Partnership had no impairment expense in 2003 compared to a $4.2 million charge in 2002, primarily related to contract valuations recorded as intangible assets as part of the Partnership's formation.

(Profit) Loss on Energy Trading Activities. The profit on energy trading activities was $1.9 million for the year ended December 31, 2003 compared to $1.7 million for the year ended December 31, 2002, a decrease of $0.2 million, or 12%. Included in these amounts are realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $2.2 million in 2003 and $1.8 million in 2002, an increase of $0.4 million, or 22%. This increase is primarily due to an increase in our producer services volumes. In addition, losses of $0.3 million and $0.1 million relating primarily to options bought and/or sold in the management of the company's Enron position were booked in 2003 and 2002, respectively.

Depreciation and Amortization. Depreciation and amortization expenses were $13.5 million for the year ended December 31, 2003 compared to $7.7 million for the year ended December 31, 2002, an increase of $5.8 million, or 75%. The increase related to the Duke assets purchased in June 2003 was $2.3 million. The Vanderbilt system, purchased in December 2002 added $1.0 million of depreciation, new treating plants placed in service in 2003 resulted in an increase of $0.9 million and the Hallmark system added $0.3 million. The remaining $1.3 million increase in depreciation and amortization is a result of expansion projects and other new assets, such as the expansion of the Gregory Plant.

Interest Expense. Interest expense was $3.1 million for the year ended December 31, 2003 compared to $2.4 million for the year ended December 31, 2002, an increase of $0.7 million, or 29%. The increase relates primarily to bank debt incurred in the acquisition of the Duke assets in June 2003 and by higher interest rates (weighted average rate of 5.35% in 2003 compared to 4.67% in 2002).

Gain on issuance of units in the Partnership. In conjunction with the Partnership's December 2002 initial public offering of common units, we conveyed to the Partnership our entire interest in the Partnership's predecessor in exchange for (1) a 2.0% general partner interest in the Partnership, (2) 333,000 common units and (3) 4,667,000 subordinated units of the Partnership. As a result of the Partnership issuing additional units to the public in its initial public offering at a price per unit greater than our equivalent carrying value, our share of the net assets of the Partnership increased by $11.8 million. Accordingly, we recognized an $11.8 million gain in 2002.

Income Tax Expense. Our income tax provision was $10.2 million in 2003 compared to $6.9 million in 2002, an increase of approximately $3.3 million. This increase was primarily due to the increase in the gain on issuance of units of the Partnership and the increase in operating income. We did not have a current tax liability in 2003 due to the availability of our net operating loss carryforward.

Interest of Non-controlling Partners in the Partnership's Net Income. We recorded an expense of $5.2 million in 2003 and $99,000 in 2002 associated with the interest of non-controlling partners' in the Partnership. We owned all of the interests in the Partnership and its predecessors until its December 2002 initial public offering.

Net Income (Loss). Net income for the year ended December 31, 2003 was $13.4 million compared to $5.2 million for the year ended December 31, 2002, an increase of $8.2 million. This increase in net income was principally the result of the increase of $6.6 million in gains on issuance of units in the Partnership and the increase in gross margin of $27.4 million from 2002 to 2003, offset by increases in ongoing cash costs for operating expenses general and administrative expenses, interest expense and income taxes as discussed above. Non-cash charges for depreciation and amortization expenses and stock based compensation also increased.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

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.

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

Prior to January 1, 2001, financial instruments which qualified for hedge accounting were accounted for using the deferral method of accounting, whereby unrealized gains and losses were generally not recognized until the physical delivery required by the contracts was made.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133 ("SFAS No. 133"), *Accounting for Derivative Instruments and Hedging Activities.* In accordance with SFAS No. 133, all derivatives and hedging instruments are recognized as assets or liabilities at fair value. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that it does not own. We refer to these activities as part of producer services. In some cases, the Partnership earns an agency fee from the producer for arranging the marketing of the producer's natural gas which is recognized net in profit from energy trading activities. 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. Where the Partnership takes title to the natural gas, the purchase contract is recorded as cost of gas purchased and the sales contract is recorded as revenue upon delivery.

The Partnership manages its price risk related to future physical purchase or sale commitments for producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance its future commitments and significantly reduce its risk to the movement in natural gas prices. However, the Partnership is subject to counterparty risk for both the physical and financial contracts. Prior to October 26, 2002, we accounted for our producer 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-basis accounting rather than mark-to-market accounting unless the contracts meet the requirements of a derivative under SFAS No. 133. The Partnership's energy trading contracts qualify as derivatives, and accordingly, we continue to use mark-to-market accounting for both physical and financial contracts of its producer 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 producer services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

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 realized gains or losses on settled activities are reported as profit or loss on energy trading activities in the statements of operations.

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

Impairment of Long-Lived Assets. In accordance with 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;
- the Partnership's ability to negotiate favorable sales agreements;
- the risks that natural gas exploration and production activities will not occur or be successful;
- the Partnership's dependence on certain significant customers, producers, and transporters of natural gas; and
- competition from other midstream companies, including major energy producers.

Any significant variance in any of the above assumptions or factors could materially affect 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 $46.3 million for the year ended December 31, 2004 compared to cash provided by operations of $42.1 million for the year ended December 31, 2003. Income before non-cash income and expenses was $46.4 million in 2004 and $27.7 million in 2003. Changes in working capital used $0.1 million in cash flows from operating activities in 2004 and provided $14.4 million in cash flows from operating activities in 2003. 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, 2004 Compared to Year Ended December 31, 2003." Changes in working capital are primarily due to the timing of collections at the end of the quarterly periods. The Partnership collects and pays 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.

Net cash used in investing activities was $124.4 million and $110.3 million for the year ended December 31, 2004 and 2003, respectively. 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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

buying, refurbishing and installing treating plants ($24.5 million). Net cash used in investing activities during 2003 related to the DEFS acquisition ($68.1 million) together with internal growth projects consisting of the Gregory plant expansion ($7.4 million), improvements to the Vanderbilt system ($4.7 million), and buying, refurbishing and installing treating plants ($9.9 million).

Net cash provided by financing activities was $99.1 million and $65.9 million for the years ended December 31, 2004 and 2003, respectively. Financing activities for 2004 relate principally to the funding of the LIG and CPP acquisitions and the funding of internal growth projects discussed above from bank borrowings and borrowings under the senior secured notes. Financing activities in 2003 relate principally to the funding of the DEFS assets acquisition and internal growth projects discussed above from bank borrowings and proceeds from the sale of common units discussed below. Financing activities also included an increase in drafts payable of $28.2 million for the year ended December 31, 2004 and a decrease in drafts payable of $17.1 million for the year ended December 31, 2003. 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 $18.3 million as of December 31, 2004, primarily due to drafts payable of $38.7 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 $100.0 million acquisition credit facility to fund checks as they are presented. As of December 31, 2004, we had $67.0 million of available borrowings under this facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2004 and 2003.

September 2003 Sale of Common Units. In September 2003, the Partnership completed a public offering of 3,450,000 common units at a public offering price of $17.985 per common unit. It received net proceeds of approximately $59.1 million, including an approximate $1.3 million capital contribution by us. The net proceeds were used to repay borrowings outstanding under the bank credit facility of the Partnership’s operating partnership.

Crosstex Energy, Inc. Initial Public Offering. In January 2004, we completed an initial public offering of our common stock whereby our existing shareholders sold 2,306,000 shares of common stock and we issued 345,900 shares of common stock at a public offering price of $19.50 per share. We received net proceeds of approximately $5.2 million from the common stock issuance. Additionally, and in conjunction with the public offering, our existing shareholders also repaid approximately $4.9 million in shareholder notes receivable. We had $22.5 million cash on hand at December 31, 2004, and we have no annual capital expenditure requirements. As a result, we believe we have adequate cash on hand for our operating requirements for the foreseeable future.

Capital Requirements of the Partnership. The natural gas gathering, transmission, treating and processing businesses are capital-intensive, requiring significant investment to maintain and upgrade existing operations. The Partnership’s capital requirements have consisted primarily of, and it anticipates 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 the Partnership’s 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 the Partnership’s 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.

Given the Partnership’s objective of growth through acquisitions, it anticipates that it will continue to invest significant amounts of capital to grow and acquire assets. The Partnership actively considers a variety of assets for potential acquisitions.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

The Partnership believes that cash generated from operations will be sufficient to meet its present quarterly distribution level of $0.45 per quarter and to fund a portion of its anticipated capital expenditures through December 31, 2005. Total capital expenditures are budgeted to be approximately $42 million in 2005 although we anticipated significantly higher capital expenditures due to pending projects such as the North Texas Pipeline Project. The Partnership expects to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below, and future issuances of units. The Partnership's ability to pay distributions to its unit holders and to fund planned capital expenditures and to make acquisitions will depend upon its future operating performance, which will be affected by prevailing economic conditions in its industry and financial, business and other factors, some of which are beyond its control.

Total Contractual Cash Obligations. A summary of the Partnership's total contractual cash obligations as of December 31, 2004, is as follows:

	Payments Due by Period						
	Total	2005	2006	2007	2008	2009	Thereafter
				(In millions)			
Long-Term Debt	$ 148.7	$ 0.1	$ 39.5	$ 10.0	$ 9.4	$ 9.4	$ 80.3
Capital Lease Obligations	—	—	—	—	—	—	—
Operating Leases	8.7	1.8	1.5	1.4	1.3	1.2	1.5
Unconditional Purchase Obligations	—	—	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—	—
Total Contractual Obligations	$ 157.4	$ 1.9	$ 41.0	$ 11.4	$ 10.7	$ 10.6	$ 81.8

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

Description of Indebtedness

As of December 31, 2004 and 2003, long-term debt consisted of the following (dollars in thousands):

	December 31, 2004	December 31, 2003
Acquisition credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at December 31, 2004 and 2003 were 4.99% and 2.92%, respectively	$ 33,000	$ 20,000
Senior secured notes, weighted average interest rate of 6.95% and 6.93% at December 31, 2004 and 2003, respectively	115,000	40,000
Note payable to Florida Gas Transmission Company	700	750
	148,700	60,750
Less current portion	(50)	(50)
Debt classified as long-term	$ 148,650	$ 60,700

Bank Credit Facility. In April 2004 the Partnership amended its $120 million senior secured credit facility with Union Bank of California, N.A. (as a lender and as administrative agent) and other lenders, to increase the credit facility to $200 million, consisting of the following two facilities:

• a $100.0 million senior secured revolving acquisition facility; and

• a $100.0 million senior secured revolving working capital and letter of credit facility.

The acquisition facility was used for the LIG acquisition in April 2004 and will be used to finance future acquisition and development of gas gathering, treating and processing facilities, as well as general partnership purposes. At December 31, 2004, $33.0 million was outstanding under the acquisition facility, leaving

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

approximately $67.0 available for future borrowings. The acquisition facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the acquisition credit facility may be re-borrowed.

The working capital and letter of credit facility will be used for ongoing working capital needs, letters of credit, distributions to partners and general partnership purposes, including future acquisitions and expansions. At December 31, 2004 the Partnership had $65.7 million of letters of credit issued under the $100.0 million working capital and letter of credit facility, leaving approximately $34.3 million available for future issuances of letters of credit and/or cash borrowings. The aggregate amount of borrowings under the working capital and letter of credit facility is subject to a borrowing base requirement relating to the amount of our cash and eligible receivables (as defined in the credit agreement), and there is a $50.0 million sublimit for cash borrowings. This facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the working capital and letter of credit facility may be re-borrowed. The Partnership is required to reduce all working capital borrowings to zero for a period of at least 15 consecutive days once each year.

The obligations under the bank credit facility are secured by first priority liens on all of the Partnership's material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of its equity interests in certain of its subsidiaries, and rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by its significant subsidiaries and by the Partnership. The Partnership 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 acquisition facility and the working capital and letter of credit facility bear interest at the Partnership's option at the administrative agent's reference rate plus 0.25% to 1.00% or LIBOR plus 1.75% to 2.50%. The applicable margin varies quarterly based on its leverage ratio. The fees charged for letters of credit range from 1.50% to 1.75% per annum, plus a fronting fee of 0.125% per annum. The Partnership will incur quarterly commitment fees based on the unused amount of the credit facilities.

The credit agreement prohibits the Partnership 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 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 its operating partnership's partnership agreement; and
- engage in transactions with affiliates.

The bank credit facility also contains covenants requiring the Partnership to maintain:

- a maximum ratio of total funded debt to consolidated EBITDA (each as defined in the bank credit facility), measured quarterly on a rolling four-quarter basis, of 3.75 to 1 through March 31, 2004, declining to 3.5 to 1 beginning June 30, 2004, pro forma for any asset acquisitions; and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis, equal to 3.50 to 1.

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 its 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, 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.

The following is a summary of the material terms of the senior secured notes.

The 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 the 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 of our equity interests in certain of our subsidiaries. The senior secured notes are guaranteed by the Partnership and its subsidiaries.

The initial $40.0 million of senior secured notes are redeemable, at the Partnership's 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 provide for a call premium of 103.5% of par beginning June 2007 through 2013 at rates declining from 103.5% to 100.0%. The notes are not callable prior to June 2007.

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.

The Partnership was in compliance with all debt covenants at December 31, 2004 and 2003 and expects 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 the Partnership and its subsidiaries. This agreement appointed Union Bank of California, N.A. to act as collateral agent and authorized Union 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 the Partnership's and its subsidiaries' obligations under the bank credit facility and the master shelf agreement.

Credit Risk

The Partnership is diligent in attempting to ensure that it issues credit to only credit-worthy customers. However, the Partnership's purchase and resale of gas exposes it to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to its overall profitability.

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, 2002, 2003 or 2004. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and the Partnership's existing agreements, it has and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental and Other Contingencies

The Partnership's operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The Partnership believes it is in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us. See Item 1. "Business — Environmental Matters."

In March 2005, the Partnership has received a claim of approximately $700,000 for damages and lost profits from one of its customers. The claim relates to an October 2004 incident in which natural gas liquids, which can drop out of the gas stream in pipelines and tend to clog the lines, were being removed from one of the Partnership's lines pursuant to normal operating procedures. Some of the liquids may have inadvertently been diverted to the customer's facilities. We have no basis at this time to evaluate the merits of the customer's claim or to reasonably estimate any potential liability it may have.

Recent Accounting Pronouncements

SFAS No 148, *Accounting for Stock-Based Compensation — Transition and Disclosure, an amendment of FASB Statement No. 123*, SFAS No. 148 amends SFAS No. 123 and provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. SFAS No. 148 also requires prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. SFAS No. 148 permits two additional transition methods for entities that adopt the fair value based method, these methods allow Companies to avoid the ramp-up effect arising from prospective application of the fair value based method. This Statement is effective for financial statements for fiscal years ending after December 15, 2002. We have complied with the disclosure provisions of the Statement in our financial statements.

In December 2004, the FASB issued SFAS No. 123 (Revised 2004), *Share-Based Payment,* which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements. This pronouncement replaces SFAS No. 123, *Accounting for Stock-Based Compensation,* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees* and will be effective beginning July 1, 2005. We have previously recorded stock compensation pursuant to the intrinsic value method under APB No. 25, whereby no compensation was recognized for most stock option awards. 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. Although we have not determined

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

the impact of SFAS 123R, the pro forma effect of recording compensation for all stock awards at fair value utilizing the Black-Scholes method for the years ended December 31, 2004, 2003 and 2002 resulted in a decrease of net income of $101,000, $57,000 and $186,000, respectively.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No 51.* In December 2003, the FASB issued FIN No. 46R which clarified certain issues identified in FIN 46. FIN No. 46R requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception for any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this interpretation must be applied at the beginning of the first interim or annual period beginning after March 15, 2004. In January 2004, the Partnership adopted FIN No. 46R and began consolidating its joint venture interest in the Crosstex DC Gathering, J.V. (CDC), previously accounted for using the equity method of accounting. The consolidated carrying amount for the joint venture is based on the historical costs of the assets, liabilities and non-controlling interests of the joint venture since its formation in January 2003 which approximates the carrying amount of the assets, liabilities and non-controlling interests in the consolidated financial statements as if FIN No. 46R had been effective upon inception of the joint venture.

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 31E 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 “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. In addition to specific uncertainties discussed elsewhere in this Form 10-K, the following risks and uncertainties may affect our performance and results of operations:

- our only cash-generating assets are our partnership interests in the Partnership, and our cash flow is therefore completely dependent upon the ability of the Partnership to make distributions to its partners;
- the value of our investment in the Partnership depends largely on the Partnership’s being treated as a partnership for federal income tax purposes;
- the amount of cash distributions from the Partnership that we will be able to distribute to you will be reduced by our expenses, including federal corporate income taxes and the costs of being a public company, and reserves for future dividends;
- so long as we own the general partner of the Partnership, we are prohibited by an omnibus agreement with the Partnership from engaging in the business of gathering, transmitting, treating, processing, storing, and marketing natural gas and transporting, fractionating, storing and marketing NGLs, except to the extent that the Partnership, with the concurrence of its independent directors comprising its conflicts committee, elects not to engage in a particular acquisition or expansion opportunity;
- in our corporate charter, we have renounced business opportunities that may be pursued by the Partnership or by affiliated stockholders that hold a majority of our common stock;
- Bryan Lawrence, the Chairman of our Board of Directors, is a senior manager at Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships (“Yorktown”), which until January 2005, in the aggregate owned more than 50% of our common shares. Yorktown has been reducing its ownership in the Company through a process of distribution of shares to its investors.

Continued distributions by Yorktown could have the effect of depressing our share price. In addition, such continued distributions could have the effect of allowing another group to take control of the Company, which might impact the nature of our future operations;

- substantially all of our partnership interest in the Partnership are subordinated to the common units, and during the subordination period, our subordinated units will not receive any distributions in a quarter until the Partnership has paid the minimum quarterly distribution of $0.25 per unit, plus any arrearages in the payment of the minimum quarterly distribution from prior quarters, on all of the outstanding common units;
- the Partnership may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to pay the minimum quarterly distribution each quarter;
- if the Partnership is unable to contract for new natural gas supplies, it will be unable to maintain or increase the throughput levels in its natural gas gathering systems and asset utilization rates at its treating and processing plants to offset the natural decline in reserves;
- the Partnership's profitability is dependent upon the prices and market demand for natural gas and NGLs, which are beyond its control and have been volatile;
- the Partnership's future success will depend in part on its ability to make acquisitions of assets and businesses at attractive prices and to integrate and operate the acquired business profitably;
- since the Partnership is not the operator of certain of its assets, the success of the activities conducted at such assets are outside its control;
- the Partnership operates in very competitive markets and encounters significant competition for natural gas supplies and markets;
- the Partnership is subject to risk of loss resulting from nonpayment or nonperformance by its customers or counterparties;
- the Partnership may not be able to retain existing customers, especially key customers, or acquire new customers at rates sufficient to maintain its current revenues and cash flows;
- the construction of gathering, processing and treating facilities requires the expenditure of significant amounts of capital and subjects the Partnership to construction risks and risks that natural gas supplies will not be available upon completion of the facilities;
- the Partnership's business is subject to many hazards, operational and environmental risks, some of which may not be covered by insurance; and
- the Partnership is subject to extensive and changing federal, state and local laws and regulations designed to protect the environment, and these laws and regulations could impose liability for remediation costs and civil or criminal penalties for non-compliance.

Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

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. The Partnership's primary market risk is the risk related to changes in the prices of natural gas and natural gas liquids (NGL's). In addition, it is also exposed to the risk of changes in interest rates on its floating rate debt.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

Commodity price risk. Approximately 8% of the natural gas the Partnership purchases 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, the Partnership's margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. The Partnership has hedged approximately 58% of its exposure to gas price fluctuations through the end of 2005.

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

The Partnership has commodity price risk associated with its processed volumes of natural gas. The Partnership currently processes gas under four main types of contractual arrangements:

1. Keep-whole contracts: Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant, and makes a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") in processing. The Partnership's margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. The Partnership controls its risk on our current keep-whole contracts through its ability to bypass processing when it is not profitable.

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

3. Theoretical processing contracts: Under these contracts, the Partnership stipulates with the producer the assumptions under which it 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 the Partnership has no commodity price exposure, and is paid a fixed fee per unit of volume that is treated or conditioned.

The Partnership's primary commodity risk management objective is to reduce volatility in its cash flows. The Partnership maintains a Risk Management Committee, including members of senior management, which oversees all hedging activity. The Partnership enters into hedges for natural gas and natural gas liquids using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by its Risk Management Committee. Hedges to protect its processing margins are generally for a more limited time frame than is possible for hedges in natural gas, as the financial markets for NGLs are not as developed as the markets for natural gas.

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

The Partnership manages its price risk related to future physical purchase or sale commitments for its producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance its future commitments and significantly reduce its risk to the movement in natural gas prices. However, the Partnership is subject to counterparty risk for both the physical and financial contracts. The Partnership accounts for certain of its 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 associated with changes in the fair value of derivatives and physical delivery contracts relating to its producer services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2004 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than October 2007, with no single contract longer than 6 months. The Partnership's counterparties to derivative contracts include BP Corporation, UBS Energy and Total Gas & Power. Changes in the fair value of the Partnership's derivatives related to third-party producers and customers gas marketing activities are recorded in earnings. 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. Fair value hedges and their underlying physical are marked to market and the changes in their fair value are recorded in earnings as profit or loss on energy trading contracts.

December 31, 2004

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
				(in thousands)
Cash Flow Hedges:				
Natural gas swaps cash flow hedge	2,088,000	Fixed prices ranging from $5.66 to $7.07 settling against various Inside FERC Index prices	January 2005 — December 2005	$ 69
Natural gas swaps cash flow hedge	(3,438,000)		January 2005 — December 2005	$ (164)
Total natural gas swaps cash flow hedge	$ (95)			
Natural gas liquids (“NGLS”) swaps cash flow hedge	(1,633,716)	Fixed prices ranging from $0.5142 to $1.115 settling against Mt. Belvieu Average of daily postings (non-TET)	January 2005 — March 2005	$ 122
Total NGL swaps cash flow hedge	$ 122			
Mark to Market Derivatives:				
Swing swaps	3,209,690	Prices ranging from Inside FERC Index less $0.525 to	January 2005 — March 2005	$ (31)
Swing swaps	(1,214,921)	Inside FERC Index plus $0.0075 settling against various Inside FERC Index prices	January 2005 — March 2005	(7)
Total swing swaps	($ 38)			
Physical offset to swing swap transactions	1,214,921	Prices ranging from Inside FERC Index less $0.01 to	January 2005 — March 2005	—
Physical offset to swing swap transactions	(3,209,690)	Inside FERC Index settling against various Inside FERC Index prices	January 2005 — March 2005	(23)
Total physical offset to swing swaps	$ (23)			
Third party on-system financial swaps	3,460,000	Fixed prices ranging from $4.83 to $7.225 settling against various Inside FERC	January 2005 — October 2007	$ (1,254)
Third party on-system financial swaps	(720,000)	Index prices	January 2005 — October 2007	$ 439
Total third party on-system financial swaps	$ (815)			

December 31, 2004				
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
				(in thousands)
Physical offset to third party on-system transactions	420,000	Fixed prices ranging from $4.675 to $6.93 settling	January 2005 — October 2007	$ (242)
Physical offset to third party on-system transactions	(3,160,000)	against various Inside FERC Index prices	January 2005 — October 2007	$ 1,264
Total physical offset to marketing trading transactions swaps	$ 1,022			
Marketing trading financial swaps	(450,000)	Fixed prices of $5.945 settling against Inside FERC Index Texas Eastern E. TX prices	January 2005 — March 2005	$ 6
Total marketing trading financial swaps	$ 6			
Physical offset to marketing trading transactions	450,000	Fixed prices of $5.855 settling against Inside FERC Index Texas Eastern E. TX prices	January 2005 — March 2005	$ 19
Total physical offset to marketing trading transactions swaps	$ 19			
	(85,000)		February 2005	$ 774
Natural gas swaps		Fixed prices ranging from $9.335 to $9.38 settling against various Inside FERC Index prices		
	$ 774			
Total natural gas swaps				

On all transactions where the Partnership is exposed to counterparty risk, it 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.

Credit Risk. The Partnership is diligent in attempting to ensure that it issues credit to only credit-worthy customers. However, its purchase and resale of gas exposes it to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to the Partnership's 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-43 of this Report and are incorporated herein by reference.

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

None.

Item 9A. *Controls and Procedures*

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2004 to provide reasonable assurance that information required to be disclosed in our reports to or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules on forms.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

There has been no change in our internal controls over financial reporting that occurred in the three months ended December 31, 2004 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.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

PART III

Item 10. *Directors and Executive Officers of the Registrant*

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

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis	43	President, Chief Executive Officer and Director
James R. Wales	51	Executive Vice President — Southern Division
A. Chris Aulds	43	Executive Vice President — Eastern Division
Jack M. Lafield	54	Executive Vice President — Corporate Development
William W. Davis	51	Executive Vice President and Chief Financial Officer
Robert S. Purgason	48	Senior Vice President — Treating Division
Michael P. Scott	50	Senior Vice President — Technical Services

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 GP, LLC, the general partner of the general partner of the Partnership. Mr. Davis holds a B.B.A. in Finance from Texas Christian University.

James R. Wales, Executive Vice President — Southern Division, 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 — Eastern Division 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, 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 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. Mr. Davis is not related to Barry E. Davis.

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.

Michael P. Scott, Senior Vice President — Technical Services, joined our predecessor in July 2001. Before joining our predecessor, Mr. Scott held various positions at Aquila Gas Pipeline Corporation, including Director of Engineering from 1992 to 2001, Director of Operations from 1990 to 1992, and Director of Project Development from 1989 to 1990. Prior to Aquila, Mr. Scott held various project development and engineering positions at Cabot Corporation/Cabot Transmission, Perry Gas Processors and General Electric. Mr. Scott holds a B.S. degree in Mechanical Engineering from Oklahoma State University.

Code of Ethics

We adopted a Code of Business Conduct and Ethics applicable to all of our employees, including all officers, and including our independent directors, who are not employees, with regard to company-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. The Code also incorporates our expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission and other public communications. A copy of our Code of Business Conduct and Ethics will be provided to any person, without charge, upon request. Contact Kathie Keller at 214-721-9327 to request a copy of a charter or send your request to Crosstex Energy, Inc., Attn: Kathie Keller, 2501 Cedar Springs, Suite 600, Dallas, Texas 75201. If any substantive amendments are made to the Code of Business Conduct and Ethics or if we grant any waiver, including any implicit waiver, from a provision of the code to any of our executive officers and directors, we will disclose the nature of such amendment or waiver in a report on Form 8-K.

Other

The sections entitled "Election of Directors", "Additional Information Regarding the Board of Directors", "Section 16(a) Beneficial Ownership Reporting Compliance", and "Stockholder Proposals and Other Matters" appearing in our proxy statement for the 2005 annual meeting of stockholders (the "2005 Proxy Statement"), set forth certain information with respect to our directors and with respect to reporting under Section 16(a) of the Securities Exchange Act of 1934, and are incorporated herein by reference.

Item 11. *Executive Compensation*

The section entitled "Executive Compensation" appearing in the 2005 Proxy Statement sets forth certain information with respect to the compensation of our management, and, except for the report of the compensation committee of our board of directors on executive compensation and the information in such section under "Performance Graph," is incorporated herein by reference.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

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

The sections entitled "Security Ownership of Certain Beneficial Owners and Management" and "Executive Compensation — Equity Compensation Plan Information" appearing in the 2005 Proxy Statement set forth certain information with respect to securities authorized for issuance under equity compensation plans and the ownership of voting securities and equity securities of us, and are incorporated herein by reference.

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

The section entitled "Certain Relationships and Related Party Transactions" appearing in the 2005 Proxy Statement sets forth certain information with respect to certain relationships and related party transactions, and is incorporated herein by reference.

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

The section entitled "Auditors" appearing in the 2005 Proxy Statement sets forth certain information with respect to accounting fees and services, and is incorporated herein by reference.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) *Financial Statements and Schedules*

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

(2) See Schedule I — Parent Company Statements on page F-40. Schedule II — Valuation and Qualifying Accounts on Page F-43.

(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	—	Restated Certificate of Incorporation of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
3.2	—	Restated Bylaws of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
3.3	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 29, 2004 (incorporated by reference from Exhibit 3.2 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.5	—	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of April 1, 2004 (incorporated by reference from Exhibit 3.3 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.6	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference from Exhibit 3.3 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

Number		Description
3.7	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.8	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference from Exhibit 3.6 to Crosstex Energy L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.10	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference from Exhibit 3.7 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.11	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference from Exhibit 3.8 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
3.12	—	Amended and Restated Certificate of Formation of Crosstex Holdings GP, LLC (incorporated by reference from Exhibit 3.11 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.13	—	Limited Liability Company Agreement of Crosstex Holdings GP, LLC, dated as of October 27, 2003 (incorporated by reference from Exhibit 3.12 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.14	—	Certificate of Formation of Crosstex Holdings LP, LLC (incorporated by reference from Exhibit 3.13 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.15	—	Limited Liability Company Agreement of Crosstex Holdings LP, LLC, dated as of November 4, 2003 (incorporated by reference from Exhibit 3.14 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.16	—	Amended and Restated Certificate of Limited Partnership of Crosstex Holdings, L.P. (incorporated by reference from Exhibit 3.15 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.17	—	Agreement of Limited Partnership of Crosstex Holdings, L.P., dated as of November 4, 2003 (incorporated by reference from Exhibit 3.16 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
4.1	—	Specimen Certificate representing shares of common stock (incorporated by reference from Exhibit 4.1 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
10.1	—	Omnibus Agreement dated December 17, 2002, among Crosstex Energy, Inc. and certain other parties (incorporated by reference from Exhibit 10.5 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.2†	—	Form of Indemnity Agreement (incorporated by reference from Exhibit 10.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.3†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan dated July 12, 2002 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.4	—	Agreement Regarding 2003 Registration Rights Agreement and Termination of Stockholders' Agreement, dated October 27, 2003 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.5†	—	Crosstex Energy, Inc. Long-Term Incentive Plan dated December 31, 2003 (incorporated by reference from Exhibit 10.5 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.6	—	Registration Rights Agreement, dated December 21, 2003 (incorporated by reference from Exhibit 10.6 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

Number		Description
10.7	—	Second Amended and Restated Credit Agreement dated November 26, 2002, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated reference from Exhibit 10.1 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.8	—	First Amendment to Second Amended and Restated Credit Agreement dated as of June 3, 2003, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference from Exhibit 10.2 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
10.9	—	Second Amendment to Second Amended and Restated Credit Agreement, dated as of June 3, 2003, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference from Exhibit 10.3 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50067).
10.10	—	Third Amendment to Second Amended and Restated Credit Agreement, dated as of April 1, 2004, by and among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference from Exhibit 10.1 to Crosstex Energy, LP.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
10.11	—	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of June 18, 2004, by and among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference from Exhibit 10.1 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, file No. 000-50067).
10.12	—	$50,000,000 Senior Secured Notes Master Shelf Agreement, dated as of June 3, 2003 (incorporated by reference from Exhibit 10.3 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
10.13	—	Letter Amendment No. 1 to Master Shelf Agreement, dated as of April 1, 2004, among Crosstex Energy Services, L.P., Prudential Investment Management, Inc., The Prudential Insurance Company of America and Pruco Life Insurance Company (incorporated by reference from Exhibit 10.2 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
10.14	—	Letter Amendment No. 2 to Master Shelf Agreement, dated as of June 18, 2004, among Crosstex Energy Services, L.P., Prudential Investment Management, Inc., The Prudential Insurance Company of America and Pruco Life Insurance Company (incorporated by reference from Exhibit 10.2 to Crosstex Energy, LP.'s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, file No. 000-50067).
10.15	—	First Contribution, Conveyance and Assumption Agreement, dated November 27, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference from Exhibit 10.2 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.16	—	Closing Contribution, Conveyance and Assumption Agreement, dated December 11, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference from Exhibit 10.3 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.17†	—	Crosstex Energy Holdings Inc. 2000 Stock Option Plan (incorporated by reference from Exhibit 10.14 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
21.1*	—	List of Subsidiaries.
23.1*	—	Consent of KPMG LLP.
31.1*	—	Certification of the principal executive officer.
31.2*	—	Certification of the principal financial officer.
32.1*	—	Certification of the principal executive officer and the principal financial officer of the Company pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

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 2005.

CROSSTEX ENERGY, INC.

By: /s/ BARRY E. DAVIS

Barry E. Davis,
President and Chief Executive Officer

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

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Director (Principal Executive Officer)	March 14, 2005
/s/ FRANK M. BURKE Frank M. Burke	Director	March 14, 2005
/s/ C. ROLAND HADEN C. Roland Haden	Director	March 14, 2005
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Chairman of the Board	March 14, 2005
Sheldon B. Lubar	Director	
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	March 14, 2005
/s/ STEPHEN A. WELLS Stephen A. Wells	Director	March 14, 2005
/s/ WILLIAM W. DAVIS William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 14, 2005

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

INDEX TO FINANCIAL STATEMENTS

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

In connection with the preparation of the Company's annual consolidate financial statements, management has undertaken an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Company's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2004, the Company's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The Company acquired the remaining outside limited and general partner interests of Crosstex Pipeline Partners (CPP) during 2004, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, CPP's internal control over financial reporting associated with total assets of $5,203,000 and total revenues of $0 included in the consolidated financial statements of Crosstex Energy, Inc. and subsidiaries as of and for the year ended December 31, 2004.

KPMG LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this report, has issued an attestation report on 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.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Crosstex Energy, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, changes in stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004. 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 schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Crosstex Energy, Inc. and subsidiaries as of December 31, 2004 and 2003, and the results of their operations, comprehensive income, and their cash flows for each of the years in the three-year period ended December 31, 2004, 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, presents 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, Inc.'s internal control over financial reporting as of December 31, 2004, 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 14, 2005, expressed an unqualified opinion on management's assessment of, and the effective operations of, internal control over financial reporting.

KPMG LLP

Dallas, Texas
March 14, 2005

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Crosstex Energy, Inc. (a Delaware Corporation) maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, 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, Inc. maintained effective internal control over financial reporting as of December 31, 2004, 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 Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Company acquired the remaining outside limited and general partner interests of Crosstex Pipeline Partners (CPP) during 2004, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, CPP's internal control over financial reporting associated with total assets of $5,203,000 and total revenues of $0 included in the consolidated financial statements of Crosstex Energy, Inc. and subsidiaries as of and for the year ended December 31, 2004. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of CPP.

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, Inc. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, changes in stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 14, 2005 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Dallas, Texas
March 14, 2005

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC.

Consolidated Balance Sheets December 31, 2004 and 2003

	December 31, 2004	December 31, 2003
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22,519	$ 1,479
Accounts receivable:		
Trade	19,453	10,238
Accrued revenues	211,700	124,517
Imbalances	573	447
Related party	61	617
Other	1,481	2,628
Note receivable	570	535
Fair value of derivative assets	3,025	4,080
Prepaid expenses, natural gas inventory, and other	5,251	2,013
Total current assets	264,633	146,554
Property and equipment:		
Transmission assets	182,602	99,650
Gathering systems	35,624	27,990
Gas plants	125,559	88,395
Other property and equipment	8,952	3,743
Construction in process	18,006	9,863
Total property and equipment	370,743	229,641
Accumulated depreciation	(45,090)	(24,751)
Total property and equipment, net	325,653	204,890
Account receivable from Enron (net of allowance of $6,931 in 2003)	1,312	1,312
Fair value of derivative assets	166	—
Intangible assets, net	5,155	5,366
Goodwill, net	6,164	6,164
Investment in limited partnerships	—	2,560
Other assets, net	3,685	3,639
Total assets	$ 606,768	$ 370,485
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Drafts payable	$ 38,667	$ 10,446
Accounts payable	3,996	6,325
Accrued gas purchases	213,037	119,900
Accounts payable-related party	—	448
Preferred dividends payable	—	3,471
Accrued imbalances payable	2,046	212
Fair value of derivative liabilities	2,085	2,487
Current portion of long-term debt	50	50
Other current liabilities	23,017	10,920
Total current liabilities	282,898	154,259
Fair value of derivative liabilities	134	—
Deferred tax liability	32,754	19,103
Long-term debt	148,650	60,700
Interest of non-controlling partners in the Partnership	65,399	67,157
Stockholders' equity:		
Convertible preferred stock (7,500,000 authorized shares, $.01 par value, -0- and 4,123,642 issued and outstanding in 2004 and 2003, respectively, $50,740 liquidation value in 2003)	—	42
Common stock (19,000,000 shares authorized, $.01 par value, 12,256,890 and 1,743,032 issued and outstanding in 2004 and 2003, respectively)	122	19
Additional paid-in capital	72,593	68,934
Retained earnings	4,214	7,549
Treasury stock, at cost (139,740 common shares in 2003)	—	(2,500)
Accumulated other comprehensive income	4	506
Notes receivable from stockholders	—	(5,284)
Total stockholders' equity	76,933	69,266
Total liabilities and stockholders' equity	$ 606,768	$ 370,485

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Operations

	Years Ended December 31, 2004	2003	2002
	(In thousands, except per share data)		
Revenues:			
Midstream	$ 1,948,021	$ 989,697	$ 437,432
Treating	30,755	23,966	14,817
Total revenues	1,978,776	1,013,663	452,249
Operating costs and expenses:			
Midstream purchased gas	1,861,204	946,412	414,244
Treating purchased gas	5,274	7,568	5,767
Operating expenses	38,197	17,758	11,420
General and administrative	21,175	11,593	7,663
Stock-based compensation	1,029	5,345	41
Impairments	981	—	4,175
(Profit) loss on energy trading activities	(2,507)	(1,905)	(1,657)
(Gain) on sale of property	(12)	—	—
Depreciation and amortization	23,034	13,542	7,745
Total operating costs and expenses	1,948,375	1,000,313	449,398
Operating (loss) income	30,401	13,350	2,851
Other income (expense):			
Interest expense, net of interest income	(9,115)	(3,103)	(2,381)
Other income (expense)	802	179	(52)
Total other income (expense)	(8,313)	(2,924)	(2,433)
Income before gain on issuance of units by the Partnership, income taxes and interest of non-controlling partners in the Partnership's net income	22,088	10,426	418
Gain on issuance of units of the Partnership	—	18,360	11,781
Income tax provision	(5,149)	(10,157)	(6,871)
Interest of non-controlling partners in the Partnership's net income	(8,239)	(5,181)	(99)
Net income	$ 8,700	$ 13,448	$ 5,229
Preferred stock dividends	$ 132	$ 3,584	$ 3,021
Net income available to common	$ 8,568	$ 9,864	$ 2,208
Basic earnings per common share	$ 0.72	$ 2.83	$ 0.59
Diluted earnings per common share	$ 0.67	$ 1.10	$ 0.46
Weighted-average shares outstanding:			
Basic	11,849	3,486	3,766
Diluted	12,899	12,271	11,361

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Changes in Stockholders' Equity

	Preferred Stock		Common Stock		Additional Paid-In Capital	Treasury Stock	Retained Earnings	Accumulated Other Compre-hensive Income	Notes Receivable	Total Stock-holders' Equity
	Shares	Amt	Shares	Amt						
	(In thousands except share data)									
Balance, December 31, 2001	3,093,642	$ 32	1,882,772	$ 19	$ 50,882	—	$ (4,523)	$ 92	$ (4,261)	$ 42,241
Issuance of preferred stock	1,000,000	10	—	—	13,990	—	—	—	—	14,000
Preferred dividends	—	—	—	—	—	—	(3,021)	—	—	(3,021)
Change in notes receivable	—	—	—	—	—	—	—	—	(474)	(474)
Stock-based compensation	—	—	—	—	41	—	—	—	—	41
Net income	—	—	—	—	—	—	5,229	—	—	5,229
Non-controlling partners' share of other comprehensive income in the Partnership	—	—	—	—	—	—	—	236	—	236
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	(116)	—	(116)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	(740)	—	(740)
Balance, December 31, 2002	4,093,642	42	1,882,772	19	64,913	—	(2,315)	(528)	(4,735)	57,396
Issuance of preferred stock	30,000	—	—	—	400	—	—	—	(360)	40
Treasury stock purchased	—	—	(139,740)	—	—	(2,500)	—	—	—	(2,500)
Stock-based compensation	—	—	—	—	3,621	—	—	—	—	3,621
Preferred dividends	—	—	—	—	—	—	(3,584)	—	—	(3,584)
Change in notes receivable	—	—	—	—	—	—	—	—	(189)	(189)
Net income	—	—	—	—	—	—	13,448	—	—	13,448
Non-controlling partners' share of other comprehensive income in the Partnership	—	—	—	—	—	—	—	298	—	298
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	1,725	—	1,725
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	(989)	—	(989)
Balance, December 31, 2003	4,123,642	42	1,743,032	19	68,934	(2,500)	7,549	506	(5,284)	69,266
Conversion of preferred to common	(4,123,642)	(42)	8,247,284	82	(40)	—	—	—	—	—
Two-for-one common stock split			1,743,032	16	(16)	—	—	—	—	—
Cancellation of treasury stock					(2,500)	2,500	—	—	—	—
Issuance of common units in public offering, net of offering costs of $1,512	—	—	345,900	3	4,794	—	—	—	—	4,797
Proceeds from exercise of stock options	—	—	177,642	2	947	—	—		—	949
Repayment of notes receivable	—	—	—	—	—	—	—	—	5,284	5,284
Stock-based compensation	—	—	—	—	474	—	—	—	—	474
Preferred dividends	—	—	—	—	—	—	(132)	—	—	(132)
Common dividends	—	—	—	—	—	—	(11,903)	—	—	(11,903)
Net income	—	—	—	—	—	—	8,700	—	—	8,700
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	(1,469)	—	(1,469)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	967	—	967
Balance, December 31, 2004	—	—	12,256,890	$ 122	$ 72,593	—	$ 4,214	$ 4	—	$ 76,933

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Comprehensive Income December 31, 2004, 2003 and 2002

	Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
Net income	$ 8,700	$ 13,448	$ 5,229
Non-controlling partners’ share of other comprehensive income in the Partnership	—	298	236
Hedging gains or losses reclassified to earnings	(1,469)	1,725	(116)
Adjustment in fair value of derivatives	967	(989)	(740)
Comprehensive income	$ 8,198	$ 14,482	$ 4,609

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Cash Flows

	Years Ended December 31, 2004	2003	2002
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 8,700	$ 13,448	$ 5,229
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	23,034	13,542	7,745
Impairments	981	—	4,175
(Income) loss on investment in affiliated partnerships	(304)	(208)	41
Gain on issuance of units of the Partnership	—	(18,360)	(11,781)
Interest of non-controlling partners in the Partnership net income	8,239	5,181	99
Deferred tax expense	4,802	10,103	6,871
Non-cash stock based compensation	982	3,967	41
Gain on sale of property	(12)	—	—
Changes in assets and liabilities net of acquisition effects:			
Accounts receivable	(48,140)	(31,782)	(47,300)
Prepaid expenses, natural gas inventory, and other	(2,817)	(1,292)	239
Accounts payable, accrued gas purchased, and other accrued liabilities	50,684	40,363	31,926
Fair value of derivatives	(752)	(389)	(4,668)
Other	942	7,530	2,333
Net cash provided by (used in) operating activities	46,339	42,103	(5,050)
Cash flows from investing activities:			
Additions to property and equipment	(45,984)	(39,003)	(14,545)
Acquisitions and asset purchases	(78,895)	(68,124)	(18,785)
Additions to other non-current assets	(115)	(1,027)	—
Proceeds from sale of property	611	—	—
Distributions from (contributions to) affiliated partnerships	12	(2,134)	90
Net cash used in investing activities	(124,371)	(110,288)	(33,240)
Cash flows from financing activities:			
Proceeds from borrowings	491,500	320,100	384,050
Payments on borrowings	(403,550)	(281,900)	(421,500)
Increase (decrease) in drafts payable	28,221	(17,100)	25,628
Distributions to non-controlling partners in the Partnership	(12,143)	(5,408)	—
Preferred dividends paid	(3,603)	(3,134)	—
Common dividends paid	(11,903)	—	—
Debt refinancing and offering costs	(1,370)	(2,200)	—
Net proceeds from issuance of units of the Partnership	—	57,958	39,568
Treasury stock purchased	—	(2,500)	—
Proceeds from exercise of common stock options	949	—	—
Proceeds from exercise of Partnership unit options	425	—	—
Repayment of shareholder notes	5,284	—	—
Net proceeds from sale of common and preferred stock	5,262	40	14,000
Net cash provided by financing activities	99,072	65,856	41,746
Net increase (decrease) in cash and cash equivalents	21,040	(2,329)	3,456
Cash and cash equivalents, beginning of period	1,479	3,808	352
Cash and cash equivalents, end of period	$ 22,519	$ 1,479	$ 3,808
Cash paid for interest	$ 7,556	$ 3,394	$ 2,558
Cash paid for income taxes	549	—	—

See accompanying notes to consolidated financial statements.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC.
Notes to Consolidated Financial Statements
December 31, 2004 and 2003

1. Organization and Summary of Significant Agreements:

(a) Description of Business

Crosstex Energy, Inc. (the "Company" and formerly Crosstex Energy Holdings Inc.), a Delaware corporation formed on April 28, 2000, is engaged, through its subsidiaries, in the gathering, transmission, treating, processing and marketing of natural gas. The Company 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 Company 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) Organization, Public Offering of Units in CELP and Public Offering of the Company

On July 12, 2002, the Company formed Crosstex Energy, L.P. (herein referred to as "the Partnership" or "CELP"), a Delaware limited partnership. On December 17, 2002, the Partnership completed an initial public offering of common units representing limited partner interests in the Partnership. Prior to its initial public offering, the Partnership was an indirect wholly owned subsidiary of the Company. The Company conveyed to the Partnership its indirect wholly owned ownership interest in Crosstex Energy Services, Ltd. (CES) in exchange for (i) a 2% general partner interest (including certain Incentive Distribution Rights) in the Partnership, (ii) 666,000 common units and (iii) 9,334,000 subordinated units of the Partnership, together representing a 67.1% limited partner interest. Prior to the conveyance of CES to the Partnership, CES distributed certain assets to the Company including (i) the Jonesville and Clarkson gas plants, (ii) the Enron receivable, and (iii) the right to receive a cash distribution of $2.5 million. As a result of CELP issuing additional units to unrelated parties, the Company's share of net assets of CELP increased by $11.1 million. Accordingly, the Company recognized a $11.8 million gain in 2002. See Note 3 for a discussion of the Partnership's September 2003 sale of additional common units.

CES constitutes the Partnership's predecessor. The transfer of ownership interests in CES to the Partnership represented a reorganization of entities under common control and was recorded at historical cost. Accordingly, the accompanying financial statements include the historical results of operations of CES prior to transfer to the Partnership.

In January 2004, the Company completed an initial public offering of its common stock. In conjunction with the public offering, the Company converted all of its preferred stock to common stock, cancelled its treasury stock and made a two-for-one stock split, effected in the form of a stock dividend. The Company's existing shareholders sold 2,306,000 common shares (on a post-split basis) and the Company issued 345,900 common shares (on a post-split basis) at a public offering price of $19.50 per common share. The Company received net proceeds of approximately $4.8 million from the common stock issuance. The Company's existing stockholders also repaid approximately $4.9 million in stockholder notes receivable in connection with the public offering. As of December 31, 2004, Yorktown owns 53.4% of the Company's outstanding common shares, Company management and directors own 17.9% of its common shares and the remaining 28.7% is held publicly.

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities and results of operations of the Company and its majority owned subsidiaries, including the Partnership. The Company proportionately consolidates the Partnership's undivided 12.4% interest in a carbon dioxide processing plant acquired by the Partnership in June 2004. In January 2004, the Company adopted FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities* ("FIN No. 46R") and began consolidating its joint

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

venture interest in Crosstex DC Gathering, J.V. as discussed more fully in Note 5. The consolidated operations are hereafter referred to collectively as the "Company." All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for the prior years to conform to the current presentation.

2. Significant Accounting Policies

(a) Management's Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management of the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates. See discussion of Enron account receivable in Note 11.

(b) Cash and Cash Equivalents

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

(c) Property, Plant, and Equipment

Property, plant and equipment consists of intrastate gas transmission systems, gas gathering systems, industrial supply pipelines, natural gas processing plants, an undivided 12.4% interest in a carbon dioxide processing plant, and gas treating plants.

Other property and equipment is primarily comprised of furniture, fixtures, and office equipment. Such items are depreciated over their estimated useful life of three to seven years. Property, plant and equipment is 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. 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 Company compares the net book value of the asset to the undiscounted expected future net cash flows. If an impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset. Impairments of $981,000 and $4.2 million were recorded in the years ended December 31, 2004 and 2002, respectively. The impairment recorded in 2004 related to a processing plant owned directly by the Company. This plant has been inactive since late 2002 when the operator of the wells behind the plant cancelled its drilling plan for the area. An impairment on the contracts associated with the plant was recorded in 2002 but the value of the plant was not impaired because the Company intended to restart or relocate the plant. Drilling activity has increased in the area near the plant and processing margins have improved during 2004 so management decided to more fully evaluate the cost of restarting this idle plant. During 2004 management determined that it would be more commercially feasible to put a new plant at the

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

plant site than to invest the capital necessary to restart the plant. If the Company does not restart the plant, our engineers estimate that the plant would receive very little, if any, value upon the sale of the plant. Therefore, the Company has impaired the full value of the plant during 2004. The impairment recorded in 2002 related primarily to customer relationships recorded as intangible assets as part of CES's formation. Due to changes impacting the expected future cash flows of the related assets, the Company determined the intangible assets were impaired under SFAS No. 121 or SFAS No. 144.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. The Company 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.

(d) Amortization of Intangibles

Until January 1, 2002, goodwill was amortized on a straight-line basis over 15 years. The Company discontinued the amortization of goodwill effective January 1, 2002 with the adoption of SFAS No. 142. As of December 31, 2004, accumulated amortization of goodwill was $674,000.

The Company has approximately $5.2 million of goodwill at December 31, 2004, which resulted from the Company's formation in May 2000. The goodwill has been allocated to the Midstream segment and is assessed at least annually for impairment. During the fourth quarter of 2004, the Company completed the annual impairment testing of goodwill and no impairment was required.

Intangible assets are amortized on a straight-line basis over the expected benefits of the customer relationships, which range from three to seven years. Such amortization was $1,211,000, $896,000, and $454,000 for the years ended December 31, 2004, 2003, and 2002, respectively. See impairment of intangibles discussed in note 2(c). As of December 31, 2004, accumulated amortization of intangible assets was $3,301,000.

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

2005	$ 1,400
2006	1,400
2007	1,149
2008	1,009
2009	132
Thereafter	55
Total	$ 5,155

(e) Other Assets

Unamortized debt issuance costs totaling $2.5 million as of December 31, 2004 are included in other non-current assets. Debt issuance costs are amortized into interest expense over the term of the related debt. Other non-current assets as of December 31, 2004 also include the non-current portion of the note receivable from RLAC Gathering Group, L.P., the minority interest partner in the joint venture discussed in Note 5.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

(f) 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 Company had an imbalance payable of $2,046,000 and $212,000 at December 31, 2004 and 2003, respectively, which approximates the fair value for these imbalances. The Company had an imbalance receivable of $573,000 and $447,000 at December 31, 2004 and 2003, respectively, which are carried at the lower of cost or market value.

(g) Revenue Recognition

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

(h) Commodity Risk Management

The Company engages in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas, oil 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 Company 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 related earnings impact recorded in the period the transactions are entered into.

In addition, certain derivative financial instruments qualify as fair value hedges. We use these instruments to hedge the value of physical storage inventory. These financial instruments and the related physical quantities are marked to market and the related earnings impact is recorded in the period the transactions were entered into.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

(i) Producer Services

The Company conducts "off-system" gas marketing operations as a service to producers on systems that the Company does not own. The Company refers to these activities as part of Producer Services. In some cases, the Company earns an agency fee from the producer for arranging the marketing of the producer's natural gas. In other cases, the Company purchases the natural gas from the producer and enters into a sales contract with another party to sell the natural gas.

The Company manages its price risk related to future physical purchase or sale commitments for its Producer Services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance the Company's future commitments and significantly reduce its risk to the movement in natural gas prices. However, the Company is subject to counterparty risk for both the physical and financial contracts. Prior to October 26, 2002, the Company accounted for its Producer 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. The Company's energy trading contracts qualify as derivatives, and accordingly, the Company continues to use mark-to-market accounting for both physical and financial contracts of its Producer Services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Company's Producer Services natural gas marketing activities are recognized in earnings as profit or loss on energy trading immediately.

For each reporting period, the Company 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 as profit or loss on energy trading in the statements of operations.

Margins earned on settled contracts from its producer services activities included in profit (loss) on energy trading contracts in the consolidated statement of operations was $2,271,000, $2,231,000, and $1,791,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

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

	Years Ended December 31,		
	2004	2003	2002
Volumes purchased and sold	76,576,000	94,572,000	84,069,000

(j) Comprehensive Income (Loss)

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, and effective January 1, 2001, unrealized gains and losses on derivative financial instruments.

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

(k) Concentrations of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

limited as the Company's customers represent a broad and diverse group of energy marketers and end users. In addition, the Company continually monitors and reviews credit exposure to its marketing counterparties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. See Note 10 for further discussion. The Company records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. As of December 31, 2004, the Company had a $59,000 reserve for uncollectible receivables. No reserve was recorded as of December 31, 2003.

During the years ended December 31, 2004, 2003, and 2002, the Company had one customer which accounted for more than 10% of consolidated revenues. The relevant percentages for this customer were: (i) for the year ended December 31, 2004 — 10.2%; (ii) for the year ended December 31, 2003 — 20.5%; and (iii) for the year ended December 31, 2002 — 27.5%. While this customer represents a significant percentage of revenues, the loss of this customer would not have a material adverse impact on the Company's results of operations.

(l) Environmental Costs

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For the years ended December 31, 2004, 2003 and 2002, such expenditures were not significant.

(m) Option Plans

The Company 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 for fixed rate stock and unit options, compensation is recorded to the extent the fair 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 the exercise price of the options at the end of the period.

Compensation expense of $1,029,000, $5,345,000 and $41,000 was recognized in 2004, 2003 and 2002, respectively. The portion of compensation expense for 2004 and 2003 related to operating activities was $199,000 and $2,122,000, respectively, and the remaining expense for the respective years of $830,000 and $3,223,000 related to general and administrative activities.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC.
Notes to Consolidated Financial Statements — (Continued)

Had compensation cost for the Company 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 Company's net income (loss) would have been as follows (in thousands except per share amounts):

	Years Ended		
	2004	2003	2002
Net income (loss), as reported	$ 8,700	$ 13,448	$ 5,229
Add: Stock-based employee compensation expense included in reported net income, net of tax	376	2,380	27
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	(477)	(2,437)	(213)
Pro forma net income (loss)	$ 8,599	$ 13,391	$ 5,043
Net income per common share, as reported:			
Basic	$ 0.72	$ 2.83	$ 0.59
Diluted	$ 0.67	$ 1.10	$ 0.46
Pro forma net income per common share:			
Basic	$ 0.71	$ 2.81	$ 0.54
Diluted	$ 0.67	$ 1.09	$ 0.44

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 2004, 2003 and 2002:

	Crosstex Energy, Inc.	
	2004	2002
Weighted average dividend yield	5.4%	0%
Weighted average expected volatility	30%	0%
Weighted average risk-free interest rate	3.26%	4.1%
Weighted average expected life	4.5 years	3 years
Contractual life	10 years	3 years
Weighted average of fair value of options granted	$4.76	$1.56

	Crosstex Energy, L.P.		
	2004	2003	2002
Weighted average dividend yield	6.4%	9.8%	10.0%
Weighted average expected volatility	29%	24%	24%
Weighted average risk-free interest rate	3.25%	2.65%	2.2%
Weighted average expected life	4.9 years	4.3 years	3 years
Contractual life	10 years	10 years	10 years
Weighted average of fair value of options granted	$4.00	$1.28	$0.58

No Company options were granted to employees, officers or directors during 2003.

(n) Sales of Securities by Subsidiaries

The Company recognizes gains and losses in the consolidated statements of income resulting from subsidiary sales of additional equity interest, including CELP limited partnership units, to unrelated parties.

(o) Recent Accounting Pronouncements

SFAS No. 148, *Accounting for Stock-Based Compensation-Transition and Disclosure, an amendment of FASB Statement No. 123.* SFAS No. 148 amends SFAS No. 123 and provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. SFAS No. 148 also requires prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. SFAS No. 148 permits two additional transition methods for entities that adopt the fair value based method; these methods allow Companies to avoid the ramp-up effect arising from prospective application of the fair value based method. This Statement is effective for financial statements for fiscal years ended after December 15, 2002. The Partnership has complied with the disclosure provisions of the Statement in its financial statements.

In December 2004, the FASB issued SFAS No. 123 (Revised 2004), *Share-Based Payment,* which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements. This pronouncement replaces SFAS No. 123, *Accounting for Stock-Based Compensation,* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees* and will be effective beginning July 1, 2005. We have previously recorded stock compensation pursuant to the intrinsic value method under APB No. 25, whereby no compensation was recognized for most stock option awards. 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 with the prospective adoption of this accounting method in July 2005. Although the Company has not determined the impact of SFAS No. 123R, the pro forma effect of recording compensation for all stock awards at fair value, utilizing the Black-Scholes method, is disclosed in *(n) Stock-Based Compensation* above.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51.* In December 2003, the FASB issued FIN No. 46R which clarified certain issues identified in FIN 46. FIN No. 46R requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception for any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this Interpretation must be applied at the beginning of the first interim or annual period ending after March 15, 2004. In January 2004, the Partnership adopted FIN No. 46R and began consolidating its joint venture interest in the Crosstex DC Gathering J.V. (CDC), previously accounted for using the equity method of accounting. The consolidated carrying amount for the joint venture is based on the historical costs of the assets, liabilities and non-controlling interests of the joint venture since its formation in January 2003 which approximates the carrying amount of the assets, liabilities and non-controlling interests in the consolidated financial statements as if FIN No. 46R had been effective upon inception of the joint venture.

In December 2004, the FASB issued Staff Position FAS 109-1 that concluded that the special tax deductions allowed under the American Jobs Creation Act of 2004 should be accounted for as a “special deduction” instead of a tax rate reduction as provided by SFAS 109. Accordingly, any tax relief the Company receives under the new tax law will be recorded as a reduction of current tax when realized, rather than an immediate reduction to its accrued deferred income tax liability.

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

(a) Initial Public Offering

On December 17, 2002, the Partnership completed its initial public offering of 4,600,000 common units representing limited partner interests at a price of $10.00 per common unit. Total proceeds from the sale of the 4,600,000 units were $46.0 million, before offering costs and underwriting commissions.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

A summary of the proceeds received from the offering and the use of those proceeds is as follows (in thousands):

Proceeds received:		
Sale of common units	$	46,000
Use of proceeds:		
Underwriters' fees	$	3,220
Professional fees and other offering costs		2,590
Repayment of debt		33,000
Distribution to Crosstex Holdings		2,500
Working capital		4,690
Total use of proceeds	$	46,000

The Crosstex Energy, L.P. partnership agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. Net income is allocated to the general partner based on incentive distributions earned for the period plus 2% of remaining net income.

(b) Sale of Additional Common 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.

(c) 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 a parity with the common units without obtaining unit-holder 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.

(d) 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. When the subordination period ends, each remaining subordinated unit will convert into one common unit and the common units will no longer be entitled to arrearages.

(e) Early Conversion of Subordinated Units

If the Partnership meets the applicable financial tests in the partnership agreement for any three consecutive four-quarter periods ending on or after December 31, 2005, 25% of the subordinated units will convert to common units. If the Partnership meets these tests for any three consecutive four-quarter periods ending on or after December 31, 2006, an additional 25% of the subordinated units will convert to common units. The early conversion of the second 25% of the subordinated units may not occur until at least one year after the early conversion of the first 25% of the subordinated units.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

(f) 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 ending 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 (6) for a description of the bank credit facility covenants.

Under the quarterly incentive distribution provisions, generally its general partner is entitled to 13% of amounts the Partnership distributes in excess of $0.25 per unit, 23% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48% of amounts the Partnership distributes in excess of $0.375 per unit. Incentive distributions totaling $5,550,000 and $954,000 were earned by the Company for the years ended December 31, 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.

4. Significant Asset Purchases and Acquisitions

On June 6, 2002, CES acquired 70 miles of then-inactive pipeline from Florida Gas Transmission Company for $1,474,000 in cash and a $800,000 note payable. On June 7, 2002, CES acquired the Pandale gathering system which is connected to two treating plants, one of which (the Will-O-Mills Plant) was half-owned by CES, from Star Field Services for $2,156,000 in cash. CES purchased the other one-half interest in the Will-O-Mills Plant on December 30, 2002 for $2,200,000 in cash.

On December 19, 2002, the Partnership acquired the Vanderbilt system, which consisted of approximately 200 miles of gathering pipeline located near our Gulf Coast System from an indirect subsidiary of Devon Energy Corporation, for $12,000,000 in cash.

On June 30, 2003, the Partnership completed the acquisition of certain assets from Duke Energy Field Services, L.P. 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, the Alabama pipeline system and two small gathering systems in Louisiana. The Company has accounted for this acquisition as a business combination in accordance with SFAS No. 141, Business Combinations. The Company has utilized the purchase method of accounting for this acquisition with an acquisition date of June 30, 2003. The purchase price and allocation thereof is as follows (in thousands):

Purchase price to DEFS	$	66,356
Direct acquisition costs		1,768
Total purchase price	$	68,124
Current assets acquired	$	426
Liabilities assumed		(813)
Property, plant and equipment		67,589
Intangible assets		922
Total purchase price	$	68,124

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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC.
Notes to Consolidated Financial Statements — (Continued)

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 in April through borrowings under its amended bank credit facility.

The Company 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 amortized over three years. The Company also increased its deferred tax liability by $923,000 during 2004 because the LIG acquisition caused the Company's estimated future tax rate to increase from 35% to 36.4% due to the effect of state taxes in Louisiana.

The purchase price allocation for the LIG acquisition has not been finalized because the Company is still in the process of settling pre-acquisition liabilities with AEP.

Operating results for the DEFS assets have been included in the Statements of Operations since June 30, 2003, and operating results for the LIG assets have been included in the Statements of Operations since April 1, 2004. The following unaudited pro forma results of operations assumes that the DEFS acquisition and the LIG acquisition occurred on January 1, 2003 (in thousands, except per unit amounts):

	Pro Forma (Unaudited) Years Ended December 31,			
	2004		2003	
Revenue	$	2,108,056	$	1,922,028
Net income	$	8,325	$	10,109
Net income per common share				
Basic	$	0.69	$	1.87
Diluted	$	0.64	$	0.82
Weighted average common shares				
Basic		11,849		3,486
Diluted		12,899		12,271

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

5. 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 their 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 $570,000 from the CDC partner is included in current notes receivable as of December 31, 2004. The remaining balance of $1,083,000 is included in other non-current assets as of December 31, 2004.

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, 2002, 2003 and 2004 because it exercised significant influence in operating decisions as a general partner in CPP.

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

The Company utilized the purchase method of accounting for the acquisition of these partnership interests as follows (in thousands):

Cash paid	$ 5,030
Direct acquisition costs	173
Total purchase price	$ 5,203
Assets acquired:	
Current assets	$ 1,838
Property, plant and equipment	5,013
Liabilities assumed:	
Current liabilities	(1,648)
Total purchase price	$ 5,203

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

6. Long-Term Debt

As of December 31, 2004 and 2003, long-term debt consisted of the following (in thousands):

	2004	2003
Acquisition credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2004 and 2003 were 4.99% and 2.92%, respectively	$ 33,000	$ 20,000
Senior secured notes, weighted average interest rate of 6.95% and 6.93%, respectively	115,000	40,000
Note payable to Florida Gas Transmission Company	700	750
	148,700	60,750
Less current portion	(50)	(50)
Debt classified as long-term	$ 148,650	$ 60,700

In April 2004, the Partnership amended its $120 million senior secured credit facility with UBOC (as a lender and administrative agent) and five other banks to increase the credit facility to $200 million, consisting of the following two facilities:

- a $100.0 million senior revolving acquisition facility; and
- a $100.0 million senior secured revolving working capital and letter of credit facility.

The acquisition facility was used for the LIG 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, 2004, $33.0 million was outstanding under the acquisition facility, leaving approximately $67.0 available for future borrowings. The acquisition facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the acquisition credit facility may be re-borrowed.

The working capital and letter of credit facility will be used for ongoing working capital needs, letters of credit, distributions and general partnership purposes, including future acquisitions and expansions. At December 31, 2004, $65.7 million of letters of credit were issued under the working capital facility, leaving approximately $34.3 million available for future issuances of letters of credit and/or cash borrowings. The aggregate amount of borrowings under the working capital and letter of credit facility is subject to a borrowing base requirement relating to the amount of our cash and eligible receivables (as defined in the credit agreement), and there is a $50.0 million sub-limit for cash borrowings. This facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the working capital facility may be re-borrowed. The Partnership is required to reduce all working capital borrowings to zero for a period of at least 15 consecutive days once a year.

The Partnership's obligations under the credit facility are secured 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 of its equity interests in certain of its subsidiaries, and ranks *pari passu* in right of payment with the senior secured notes. The credit agreement is guaranteed by certain of our subsidiaries. The Partnership 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.

Indebtedness under the acquisition facility and the working capital facility bear interest at the Partnership's option at the administrative agent's reference rate plus 0.25% to 1.5% or LIBOR plus 1.75% to 2.50%. The applicable margin varies quarterly based on the Partnership's leverage ratio. The fees charged for

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

letters of credit range from 1.50% to 1.75% per annum, plus a fronting fee of 0.125% per annum. The Partnership incurs quarterly commitment fees based on the unused amount of the credit facilities.

The credit agreement prohibits the Partnership 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 funded debt to consolidated EBITDA (each as defined in the bank credit facility), measured quarterly on a rolling four quarter basis, of 3.75 to 1 through March 31, 2004, declining to 3.5 to 1 beginning June 30, 2004, pro forma for any asset acquisitions; and
- a minimum interest coverage ratio (as defined in the bank credit facility), measured quarterly on a rolling four quarter basis equal to 3.50 to 1.

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's operating 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.

The 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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

of the Partnership 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 our equity interests in certain of our subsidiaries. The senior secured notes are guaranteed by the Partnership's subsidiaries.

The initial $40 million of senior secured notes are redeemable, at the Partnership's 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 provide for a call premium of 103.5% of par beginning June 2007 through 2013 at rates declining from 103.5% to 100.0%. The notes are not callable prior to June 2007.

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, 2004 and 2003 and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement in June 2004, 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 the Partnership and its subsidiaries. This agreement appointed Union Bank of California, N.A. to act as collateral agent and authorized Union Bank to execute various security documents on behalf of the lenders under the bank credit facility and the initial 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 $800,000 to FGTC that is payable in $50,000 annual increments through June 2006 with a final payment of $600,000 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, 2004 are as follows (in thousands):

2005	$	50
2006		39,520
2007		10,012
2008		9,412
2009		9,412
Thereafter		80,294

Interest Rate Swap. In October 2002, the Partnership entered into an interest rate swap covering a principal amount of $20 million for a period of two years. The Partnership is subject to interest rate risk on its acquisition credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 2.29%, on $20 million of related debt outstanding over the term of the swap agreement which expired on November 1, 2004. The Company has accounted for this swap as a cash flow hedge of the variable

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

interest payments related to the $20 million of the acquisition credit facility outstanding. Accordingly, unrealized gains or losses relating to the swap which are recorded in other comprehensive income will be reclassified from other comprehensive income to interest expense over the period hedged. The fair value of the interest rate swap at December 31, 2003 was a $209,000 liability and was included in fair value of derivative liabilities.

7. Income Taxes

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

	2004	2003	2002
Current tax provision	$ 347	$ 54	$ —
Deferred tax provision	4,802	10,103	6,871
	$ 5,149	$ 10,157	$ 6,871

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

	2004	2003	2002
Federal income tax at statutory rate (35%)	$ 4,848	$ 8,262	$ 4,235
State income taxes, net	193	—	—
Tax basis adjustment in Partnership related to issuance of common units	—	1,895	2,620
Non-deductible expenses	91	—	16
Other	17	—	—
Tax provision	$ 5,149	$ 10,157	$ 6,871

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

	2004	2003
Deferred income tax assets:		
Net operating loss carryforward	$ 5,224	$ 3,742
Enron reserve	154	2,386
Investment in the Partnership	4,347	4,179
Other	49	—
	9,774	10,307
Less: valuation allowance	(4,347)	(4,179)
	5,427	6,128
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets	(38,004)	(24,913)
Other comprehensive income	(2)	(273)
Other	(175)	(45)
	(38,181)	(25,231)
Net deferred tax liability	$ (32,754)	$ (19,103)

At December 31, 2004, the Company had a net operating loss carryforward of approximately $14.8 million that expires from 2021 through 2024. The Company also has various state net operating loss carryforwards

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

of approximately $ 0.6 million which will begin expiring in 2016. Management believes that it is more likely than not that the future results of operations will generate sufficient taxable income to utilize these net operating loss carryforwards before they expire. Although the Company has generated net operating losses in the past and expects to generate a net operating loss in 2005, the Company expects to have significant amounts of future taxable income from its investment in the Partnership, particularly because of the remedial allocations of income among the unitholders and the allocation of income based on the Company's incentive distribution rights.

Deferred tax liabilities relating to property, plant, equipment and intangible assets represent, primarily, the Company's share of the book basis in excess of tax basis for assets inside of the Partnership. The Company has also recorded a deferred tax asset in the amount of $4.3 million relating to the difference between its book and tax basis of its investment in the Partnership. Because the Company can only realize this deferred tax asset upon the liquidation of the Partnership and to the extent of capital gains, the Company has provided a full valuation allowance against this deferred tax asset. The valuation allowance increased $168,000 from 2003 to 2004 due to the increase in the future expected tax rate from 35% in 2003 to 36.4% in 2004. The increase in the future expected tax rate was directly related to the provision for the effect of state taxes on the April 2004 LIG acquisition. A substantial portion of the Company's assets were located in Texas prior to 2004 and the state of Texas does not assess a business income tax.

8. 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 $259,000 and $198,000 for the years ended December 31, 2003 and December 31, 2002, respectively.

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 to the plan for the year ended December 31, 2004 were $479,000.

9. Employee Incentive Plans

(a) Long-Term Incentive Plan

In December 2002, the Partnership adopted a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 1,400,000 common unit options and restricted units. The plan is administered by the compensation committee of the Partnership'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 the Company.

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.

In May 2003, 96,000 restricted units were issued to senior management under the long-term incentive plan with an intrinsic value of $1,247,000. In September 2003, 2,150 restricted units with an intrinsic value of $39,000 were issued to a director, at his election, for his 2003 annual director fee. These restricted units vest over a five-year period and the intrinsic value of the units is amortized into stock-based compensation expense over the vesting period. The Company recognized stock-based compensation expense of $257,000 and $197,000 related to the amortization of these restricted units in 2004 and 2003, respectively.

(c) Partnership 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 the Company.

A summary of the unit option activity for the years ended December 31, 2004, 2003 and 2002 is provided below:

	Years Ended December 31,					
	2004		2003		2002	
	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	643,272	$ 10.28	350,000	$ 10.00	—	—
Granted	466,296	22.52	294,772	10.61	350,000	$ 10.00
Exercised	(39,066)	11.00	—	—	—	—
Forfeited	(26,637)	15.64	(1,500)	10.00	—	—
Outstanding, end of period	1,043,865	$ 15.58	643,272	$ 10.28	350,000	$ 10.00
Options exercisable at end of period	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	350,000	$ 0.58
Weighted average fair value of options granted with an exercise price less than market price at grant	349,394	$ 3.70	10,752	$ 3.54	—	—

The following table summarizes information about outstanding options as of December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$10.00-$11.63	572,941	8.1 Years	$ 10.03	253,796	$ 10.01
$16.50-$18.25	48,200	8.9 Years	$ 17.40	6,667	$ 18.15
$21.25-$23.90	307,679	9.1 Years	$ 21.27	2,615	$ 23.90
$25.75-$30.00	115,045	9.6 Years	$ 27.20	—	$ —
Total	1,043,865	8.6 Years	$ 15.57	263,078	$ 10.36

The Company 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.* In September 2003, two directors elected to receive options to purchase 10,752 common units (in aggregate) in the Partnership for 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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

grant date, the Company 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

The Company 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.

The Company 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 for fixed rate options, 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.

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. Compensation expense of $47,000, $5,041,000 and $41,000 was recognized in 2004, 2003 and 2002, respectively, related to the Company's stock options. As discussed below, the Company modified certain options during 2003 which accounted for using variable accounting.

A summary of the status of the 2000 Stock Option Plan as of December 31, 2004 and 2003, is presented in the table below:

	Years Ended December 31,					
	2004		2003		2002	
	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	862,390	$ 5.42	1,040,500	$ 5.39	681,000	$ 5.16
Granted	43,636	25.44	—	—	372,500	5.95
Cancelled	(8,000)	5.13	(176,110)	5.20	—	—
Exercised	(177,642)	5.34	—	—	—	—
Forfeited	—	—	(2,000)	6.00	(13,000)	6.00
Outstanding, end of period	720,384	$ 6.66	862,390	$ 5.42	1,040,500	$ 5.39
Options exercisable at end of period	662,083	$ 5.55	711,213	$ 5.29	577,006	$ 5.18
Weighted average fair value of options granted with an exercise price equal to market price at grant	40,000	$ 4.50	—	—	372,500	$ 1.56
Weighted average fair value of options granted with an exercise price less than market price at grant	3,636	$ 7.58	—	—	—	—

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

The following table summarizes information about outstanding options as of December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 5.00-$7.00	666,748	0.4 Years	$ 5.38	651,780	$ 5.35
$10.00	10,000	0.4 Years	$ 10.00	6,667	$ 10.00
$19.50	30,000	9.0 Years	$ 19.50	—	$ —
$34.37	3,636	9.0 Years	$ 34.37	3,636	$ 34.37
$40.00	10,000	9.8 Years	$ 40.00	—	$ —
	720,384	0.9 Years	$ 6.66	662,083	$ 5.60

The Company 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 its options which have been modified is approximately 364,000. These modified options have been accounted for using variable accounting as of the option modification date. The Company accounted for the modified options as variable options until the holders elected to cash out the options or the election to cash out the options lapsed. The Company 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 Company ceased applying variable accounting to the remaining modified options. The Company recognized stock-based compensation expense of approximately $5.0 million related to the variable options for the year ended December 31, 2003.

In 2004, 85,000 restricted shares were issued to members of management under its long-term incentive plan with an intrinsic value of $2,579,000. 80,000 of the restricted shares vest over a five-year period and 5,000 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 share and anti-dilutive computations

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

In conjunction with the Company's initial public offering in January 2004, the Company affected a two-for-one split. All unit amounts for prior periods presented herein have been restated to reflect this stock split.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC.
Notes to Consolidated Financial Statements — (Continued)

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

	Years Ended December 31, 2004	2003	2002
Basic earnings per share:			
Weighted average common shares outstanding	11,849	3,486	3,766
Dilutive earnings per share:			
Weighted average common shares outstanding	11,849	3,486	3,766
Dilutive effect of restricted shares	73	—	—
Dilutive effect of exercise of options	706	573	235
Dilutive effect of exercise of preferred stock conversion to common shares	271	8,212	7,360
Dilutive units	12,899	12,271	11,361

All outstanding common shares were included in the computation of diluted earnings per common share.

10. Fair Value of Financial Instruments

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

	December 31, 2004		December 31, 2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 22,519	$ 22,519	$ 1,479	$ 1,479
Trade accounts receivable and accrued revenues	231,153	231,153	134,755	134,755
Fair value of derivative assets	3,191	3,191	4,080	4,080
Account receivable from Enron	1,312	1,312	1,312	1,312
Note receivable	1,653	1,653	1,563	1,563
Accounts payable, drafts payable and accrued gas purchases	255,700	255,700	136,671	136,671
Long-term debt	148,650	157,231	60,750	60,750
Fair value of derivative liabilities	2,219	2,219	2,487	2,487

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities. The carrying amount of the account receivable from Enron approximates the fair value based on the estimated recoverable value for our claim in its bankruptcy proceedings as discussed in Note 11. 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 $33.0 million and $20.0 million as of December 31, 2004 and 2003, 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, 2004, the Company also had borrowings totaling $115.0 million under senior secured notes with a weighted average interest rate of 6.95%. The fair value of these borrowings as of December 31, 2004 was adjusted to reflect to current market interest rate for such borrowings as of December 31, 2004.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

The fair value of derivative contracts included in assets or liabilities represents the amount at which the instruments could be exchanged in a current arms-length transaction.

11. Derivatives

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

	December 31, 2004	December 31, 2003
Fair value of derivative assets — current	$ 3,025	$ 4,080
Fair value of derivative assets — long term	166	—
Fair value of derivative liabilities — current	(2,085)	(2,278)
Fair value of derivative liabilities — long term	(134)	—
Net fair value of derivatives	$ 972	$ 1,802

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2004 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than October 2007, with no single contract longer than 6 months. The Company's counterparties to derivative contracts include BP Corporation, UBS Energy, and Total Gas & Power. As discussed in note 2, changes in the fair value of the Company's derivatives related to Producer Services 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. Fair value hedges and their underlying physical are marked to market and the changes in their fair value are recorded in earnings as profit or loss on energy trading contracts.

December 31, 2004

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Cash Flow Hedge:				
Natural gas swaps cash flow hedge	2,088,000	Fixed prices ranging from $5.66 to $7.07 settling against various Inside FERC Index prices	January 2005 - December 2005	$ 69
Natural gas swaps cash flow hedge	(3,438,000)		January 2005 - December 2005	$ (164)
Total natural gas swaps cash flow hedge	$ (95)			
Natural gas liquids ("NGLS") swaps cash flow hedge	(1,633,716)	Fixed prices ranging from $0.5142 to $1.115 settling against Mt. Belvieu Average of daily postings (non-TET)	January 2005 - March 2005	$ 122
Total NGL swaps cash flow hedge	$ 122			

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC.
Notes to Consolidated Financial Statements — (Continued)
December 31, 2004

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
				(In thousands)
Mark to Market Derivatives:				
Swing swaps	3,209,690	Prices ranging from Inside FERC Index less $0.525 to Inside FERC Index plus $0.0075 settling against various Inside FERC Index prices	January 2005 - March 2005	$ (31)
Swing swaps	(1,214,921)		January 2005 - March 2005	(7)
Total swing swaps mark to market hedges				$ (38)
Physical offset to swing swap transactions	1,214,921	Prices ranging from Inside FERC Index less $0.01 to Inside FERC Index settling against various Inside FERC Index prices	January 2005 - March 2005	—
Physical offset to swing swap transactions	(3,209,690)		January 2005 - March 2005	(23)
Total physical offset to swing swaps				$ (23)
Third party on-system financial swaps	3,460,000	Fixed prices ranging from $4.83 to $7.225 settling against various Inside FERC Index prices	January 2005 - October 2007	$ (1,254)
Third party on-system financial swaps	(720,000)		January 2005 - October 2007	$ 439
Total third party on-system financial swaps				$ (815)
Physical offset to third party on-system transactions	420,000	Fixed prices ranging from $4.675 to $6.93 settling against various Inside FERC Index prices	January 2005 - October 2007	$ (242)
Physical offset to third party on-system transactions	(3,160,000)		January 2005 - October 2007	$ 1,264
Total physical offset to marketing trading transactions swaps				$ 1,022
Marketing trading financial swaps	(450,000)	Fixed prices of $5.945 settling against Inside FERC Index Texas Eastern E. TX prices	January 2005 - March 2005	$ 6
Total marketing trading financial swaps				$ 6
Physical offset to marketing trading transactions	450,000	Fixed prices of $5.855 settling against Inside FERC Index Texas Eastern E. TX prices	January 2005 - March 2005	$ 19
Total physical offset to marketing trading transactions swaps				$ 19

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC.
Notes to Consolidated Financial Statements — (Continued)

December 31, 2004

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
				(In thousands)
Natural gas swaps	(85,000)	Fixed prices ranging from $9.335 to $9.38 settling against various Inside FERC Index prices	February 2005	$ 774
Total natural gas swaps				$ 774

On all transactions where the Company is exposed to counterparty risk, the Company 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.

Assets and liabilities related to Producer Services that are accounted for as energy trading contracts are included in the fair value of derivative assets and liabilities. The Company estimates the fair value of all of its energy trading contracts using prices actively quoted. 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, 2004	$ 25	—	—	$ 25

Account Receivable from Enron

On December 2, 2001, Enron Corp. and certain subsidiaries, including Enron North America Corp. ("Enron"), each filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code. The Company has allowed unsecured claims in the Enron bankruptcy matter which total approximately $7.8 million. The Company has written these claims down to $1.3 million at December 31, 2004, which is the estimate of recoverable value pursuant to the bankruptcy plan as confirmed by the bankruptcy court in July 2004.

12. Transactions with Related Parties

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, 2004, 2003 and 2002, the Partnership purchased natural gas from Camden in the amount of approximately $38.4 million, $8.4 million and $10.1 million, respectively, and received approximately $2.4 million, $190,000 and $399,000 in treating fees from Camden.

Crosstex Pipeline Partners, L.P.

During the three years ended December 31, 2004, the Partnership was the general partner and a limited partner in CPP as discussed in Note 5. The Partnership had related-party transactions with CPP, as summarized below:

- During the years ended December 31, 2004, 2003 and 2002, the Partnership bought natural gas from CPP in the amount of approximately $11.6 million, $8.2 million and $3.4 million and paid for transportation of approximately $51,000, $41,000 and $27,500, respectively, to CPP.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

- During the years ended December 31, 2004, 2003 and 2002, the Partnership received a management fee from CPP in the amount of approximately $125,000, $125,000 and $125,000 respectively.
- During the years ended December 31, 2004, 2003 and 2002, the Partnership received distributions from CPP in the amount of approximately $159,000, $104,000 and $90,000, respectively.

13. Commitments and Contingencies

(a) Leases —Lessee

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

2005	$ 1,817
2006	1,522
2007	1,398
2008	1,261
2009	1,199
Thereafter	1,518
	$ 8,715

Operating lease rental expense for the years ended December 31, 2004, 2003 and 2002 was approximately $2,849,000, $1,812,000 and $951,000, respectively.

(b) Leases —Lessor

During 2004 the Company leased approximately 15 of its treating 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 cancellable leases. As of December 31, 2004, the Company only had four treating plants under operating leases with remaining non-cancellable lease terms in excess of one year. The future minimum lease rentals are $517,000 and $332,000 for the years ended December 31, 2005 and 2006, respectively. These leased treating plants have a cost of $3,792,000 and accumulated depreciation of $442,000 as of December 31, 2004.

(c) Employment Agreements

Certain members of management of the Company are parties to employment contacts with the general partner. The employment agreements provide each member of senior management 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 two assets from DEFS in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas and a compressor station near Cadeville, Louisiana. At both of these sites, 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 remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million, and the remediation cost for the Cadeville site is currently estimated to be approximately $1.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of both the Conroe and Cadeville sites. 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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

company that specializes in remediation work. In addition, effective September 1, 2004, the Partnership sold its Cadeville assets, including the compressor station and gathering system, subject to the retained DEFS indemnity, to a third party. The Company does not expect to incur any material environmental liability associated with the Conroe or Cadeville sites.

The Partnership acquired LIG Pipeline Company and its subsidiaries on April 1, 2004. Contamination from historical operations has been identified at a number of sites within the acquired properties. The seller, AEP, has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third-party company pursuant to which the remediation costs associated with these sites have been assumed by this third-party company that specializes in remediation work. The Company does not expect to incur any material liability with these sites. The Partnership has disclosed these deficiencies to Louisiana Department of Environmental Quality and is working with the department to correct permit conditions and address modifications to facilities to bring them into compliance. The Company does not expect to incur any material environmental liability associated with these issues.

(e) Other

The 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.

In May 2003, four landowner groups filed suit against us in the 267th Judicial District Court in Victoria County, Texas seeking damages related to the expiration of an easement for a segment of one of our pipelines located in Victoria County, Texas. In 1963, the original owners of the land granted an easement for a term of 35 years, and the prior owner of the pipeline failed to renew the easement. The Partnership filed a condemnation counterclaim in the district court suit and it filed, in a separate action in the county court, a condemnation suit seeking to condemn a 1.38-mile long easement across the land. Pursuant to condemnation procedures under the Texas Property Code, three special commissioners were appointed to hold a hearing to determine the amount of the landowner's damages. In August 2004, a hearing was held and the special commissioners awarded damages to the current landowners in the amount of $877,500. The Partnership has timely objected to the award of the special commissioners and the condemnation case will now be tried in the county court. The damages award by the special commissioners will have no effect and cannot be introduced as evidence in the trial. The county court will determine the amount that the Partnership will pay the current landowners for an easement across their land and will determine whether or not and to what extent the current landowners are entitled to recover any damages for the time period that there was not an easement for the pipeline on their land. Under the Texas Property Code, in order to maintain possession of and continued use of the pipeline until the matter has been resolved in the county court, the Partnership was required to post bonds and cash, each totaling the amount of $877,500, which is the amount of the special commissioners award. The Company is not able to predict the ultimate outcome of this matter.

In March 2005, the Company has received a claim of approximately $700,000 for damages and lost profits from one of its customers. The claim relates to an October 2004 incident in which natural gas liquids, which can drop out of the gas stream in pipelines and tend to clog the lines, were being removed from one of the company's lines pursuant to normal operating procedures. Some of the liquids may have inadvertently been diverted to the customer's facilities. The Company has no basis at this time to evaluate the merits of the customer's claim or to reasonably estimate any potential liability it may have.

14. Capital Stock

(a) Convertible Preferred Stock

The Company has authorized 3,500,000 shares of Convertible Preferred Stock — A, 1,000,000 shares of Convertible Preferred Stock — B and 3,000,000 shares of Convertible Preferred Stock — C, all shares with

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

$.01 par values. At December 31, 2003 the Company had 2,579,743 shares of Convertible Preferred Stock — A issued and outstanding. At December 31, 2003 the Company had 523,899 shares of Convertible Preferred Stock — B issued and outstanding. At December 31, 2003 the Company had 1,020,000 shares of Convertible Preferred Stock — C Shares issued and outstanding. All preferred shares accrued dividends at a rate of 7.5% per year.

In January 2004, the Company converted all its preferred stock to common stock in conjunction with its initial public offering discussed in Note 1(b).

(b) Common Stock

The Company has authorized 19,000,000 shares of common stock at $.01 par value. At December 31, 2004 and 2003 the Company had 12,254,246 and 1,743,032 shares, respectively, issued and outstanding. In January 2004, the Company made a two-for-one stock split in conjunction with its initial public offering discussed in Note 1(b).

The Company paid annual common dividends of $1.37, $0 and $0 per share for the years ended December 31, 2004, 2003 and 2002, respectively.

(c) Notes Receivable

In 2000, and 2003, shares of common stock and preferred stock were sold to certain members of management in return for notes receivable. The notes receivable were guaranteed by the related stock and bore interest. The common stock and preferred stock sold to management were sold at fair value as evidenced by the price paid by third parties. Accordingly, no compensation expense was recorded on the stock sold to management. The stockholder notes receivable were reflected as a reduction to stockholders' equity.

In January 2004, $4.9 million in stockholder notes receivable were repaid in conjunction with the Company's initial public offering discussed in Note 1(b) and the remaining notes receivable were repaid in December 2004.

15. Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Company's reportable segments consist of Midstream and Treating. The Midstream division consists of the Company'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, and various other small systems. Also included in the Midstream division are the Company'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 policies of the operating segments are the same as those described in note 2 of the Notes to Consolidated Financial Statements. The Company evaluates the performance of its operating segments based on earnings before gain or issuance of units by CELP, income taxes, interest of non-controlling partners in CELP's net income and accounting changes, and after an allocation of corporate expenses. Corporate

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

expenses and stock based compensation 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. Intersegment sales are at cost.

Summarized financial information concerning the Company'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, 2004:			
Sales to external customers	$ 1,948,021	$ 30,755	$ 1,978,776
Intersegment sales	6,360	(6,360)	—
Interest expense	7,759	1,356	9,115
Stock based compensation	844	185	1,029
Depreciation and amortization	15,762	7,272	23,034
Segment profit	18,513	3,575	22,088
Segment assets	516,254	90,514	606,768
Capital expenditures	20,843	25,141	45,984
Year ended December 31, 2003:			
Sales to external customers	$ 989,697	$ 23,966	$ 1,013,663
Intersegment sales	6,893	(6,893)	—
Interest expense	2,464	639	3,103
Stock based compensation	4,276	1,069	5,345
Depreciation and amortization	9,623	3,919	13,542
Segment profit	8,214	2,212	10,426
Segment assets	300,076	70,409	370,485
Capital expenditures	28,728	10,275	39,003
Year ended December 31, 2002:			
Sales to external customers	$ 437,432	$ 14,817	$ 452,249
Intersegment sales	4,073	(4,073)	—
Interest expense	2,039	342	2,381
Impairments	—	4,175	4,175
Depreciation and amortization	5,738	2,007	7,745
Segment profit (loss)	1,473	(1,055)	418
Segment assets	206,393	35,031	241,424
Capital expenditures	11,154	3,391	14,545

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

16. Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(in thousands, except per share amount)				
2004:					
Revenues	$ 325,358	$ 515,531	$ 508,884	$ 629,003	$ 1,978,776
Operating income(1)	6,514	7,950	7,461	8,476	30,401
Net income	2,197	2,416	1,680	2,407	8,700
Basic earnings per common share	$ 0.19	$ 0.20	$ 0.14	$ 0.20	$ 0.72
Diluted earnings per common share	$ 0.17	$ 0.19	$ 0.13	$ 0.19	$ 0.67
2003:					
Revenues	$ 250,570	$ 229,252	$ 283,198	$ 250,643	$ 1,013,663
Operating income	605	3,631	4,047	5,067	13,350
Net income	30	1,091	11,376(1)	951	13,448
Basic earnings per common share	(0.25)	0.05	3.01	0.02	2.83
Diluted earnings per common share	(0.25)	0.05	0.92	0.02	1.10

(1) Included in the 2003 third quarter results is an $18.4 million (before taxes) gain related to the issuance of additional common units in the Partnership's September 2003 follow-on offering.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

SCHEDULE I

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED BALANCE SHEETS

	December 31, 2004	December 31, 2003
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 16,709	$ 1,313
Prepaid expenses and other	172	75
Total current assets	16,881	1,388
Investment in the Partnership	83,916	88,748
Investment in subsidiary	1,488	7,459
Other non-current assets	—	465
Total assets	$ 102,285	$ 98,060
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Preferred dividend payable	$ —	$ 3,471
Payable to the Partnership	591	886
Other accrued liabilities	12	50
Total current liabilities	603	4,407
Deferred tax liability	24,749	19,103
Stockholders' equity:		
Convertible preferred stock	—	42
Common stock	122	19
Additional paid-in capital	72,593	68,934
Retained earnings	4,214	7,549
Treasury stock, at cost	—	(2,500)
Accumulated other comprehensive income	4	506
Total stockholders' equity	76,933	74,550
Total liabilities and stockholders' equity	$ 102,285	$ 98,060

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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2004	2003	2002
	(In thousands except share data)		
Operating income and expenses:			
Income from investment in the Partnership	$ 15,754	$ 10,045	$ 245
(Loss) from investment in subsidiary	(1,044)	(1,252)	(11)
Stock-based compensation	(28)	—	—
General and administrative	(1,068)	(3,542)	(150)
Operating income	13,614	5,251	84
Other income (expense):			
Interest income	73	(6)	335
Other expense	—	—	(100)
Total other income and expense	73	(6)	235
Income before gain on issuance of units by the Partnership and income taxes	13,687	5,245	319
Gain on issuance of units in the Partnership	—	18,360	11,781
Income tax provision expense	(4,987)	(10,157)	(6,871)
Net income	$ 8,700	$ 13,448	$ 5,229
Earnings per share:			
Basic	$ 0.72	$ 2.83	$ 0.59
Diluted	$ 0.67	$ 1.10	$ 0.46

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

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF CASH FLOW

	Years Ended December 31, 2004	2003	2002
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 8,700	$ 13,448	$ 5,229
Adjustments to reconcile net income (loss) to net cash flow provided by (used in) operating activities:			
Income from investment in the Partnership	(15,754)	(10,045)	(245)
Loss from investment in subsidiary	1,044	1,252	11
Deferred taxes	4,992	10,103	6,871
Stock-based compensation	28	—	41
Gain on issuance of units in the Partnership	—	(18,360)	(11,781)
Changes in assets and liabilities:			
Accounts receivable	—	400	—
Prepaid expenses and other	(97)	(539)	299
Accounts payable and other accrued liabilities	(333)	780	48
Net cash provided by (used in) operating activities	(1,420)	(2,961)	473
Cash flows from investing activities:			
Investment in the Partnership	—	(1,263)	(14,000)
Distributions from the Partnership	21,184	9,872	2,500
Dividends from subsidiary	4,927	137	—
Net cash provided by (used in) investing activities	26,111	8,746	(11,500)
Cash flows from financing activities:			
Proceeds from sale of common and preferred stock	5,262	40	14,000
Proceeds from exercise of common stock options	949	—	—
Increase in shareholder note receivables	—	—	(473)
Preferred dividends paid	(3,603)	(3,134)	—
Common dividends paid	(11,903)	—	—
Redemptions of stock options for cash	—	(1,378)	—
Purchase of treasury stock	—	(2,500)	—
Net cash provided by (used in) financing activities	(9,295)	(6,972)	13,527
Net increase (decrease) in cash	15,396	(1,187)	2,500
Cash, beginning of year	1,313	2,500	—
Cash, end of year	$ 16,709	$ 1,313	$ 2,500

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

SCHEDULE II

CROSSTEX ENERGY, INC.

VALUATION AND QUALIFYING ACCOUNTS

		Additions			
	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
Year Ended December 31, 2004:					
For doubtful receivables classified as non-current assets	$ 6,931	—	—	$ (6,931)(b)	—
Year Ended December 31, 2003:					
For doubtful receivables classified as non-current assets	5,776	1,155(a)	—	—	6,931
Year Ended December 31, 2002:					
For doubtful receivables classified as non-current assets	5,776(a)	—	—	—	5,776

(a) Allowance for doubtful receivables on energy trading contracts related to natural gas marketing, substantially all of which relates to estimated losses from Enron claims. See Note 11 to Consolidated Financial Statements.

(b) The allowance for doubtful receivables for the Enron claims was written off against the receivable balance in 2004 pursuant to the Company's allowed claim in Enron's bankruptcy proceedings.

Source: CROSSTEX ENERGY INC, 10-K, March 15, 2005

EXHIBIT INDEX

Number		Description
3.1	—	Restated Certificate of Incorporation of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Annual Report on Form 10-K, for the year ended December 31, 2003).
3.2	—	Restated Bylaws of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K, for the year ended December 31, 2003).
3.3	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 29, 2004 (incorporated by reference from Exhibit 3.2 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.5	—	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of April 1, 2004 (incorporated by reference from Exhibit 3.3 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.6	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference from Exhibit 3.3 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.8	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference from Exhibit 3.6 to Crosstex Energy L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.10	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference from Exhibit 3.7 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.11	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference from Exhibit 3.8 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
3.12	—	Amended and Restated Certificate of Formation of Crosstex Holdings GP, LLC (incorporated by reference from Exhibit 3.11 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.13	—	Limited Liability Company Agreement of Crosstex Holdings GP, LLC, dated as of October 27, 2003 (incorporated by reference from Exhibit 3.12 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.14	—	Certificate of Formation of Crosstex Holdings LP, LLC (incorporated by reference from Exhibit 3.13 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.15	—	Limited Liability Company Agreement of Crosstex Holdings LP, LLC, dated as of November 4, 2003 (incorporated by reference from Exhibit 3.14 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.16	—	Amended and Restated Certificate of Limited Partnership of Crosstex Holdings, L.P. (incorporated by reference from Exhibit 3.15 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.17	—	Agreement of Limited Partnership of Crosstex Holdings, L.P., dated as of November 4, 2003 (incorporated by reference from Exhibit 3.16 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
4.1	—	Specimen Certificate representing shares of common stock (incorporated by reference from Exhibit 4.1 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).

Number		Description
10.1	—	Omnibus Agreement dated December 17, 2002, among Crosstex Energy, Inc. and certain other parties (incorporated by reference from Exhibit 10.5 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.2†	—	Form of Indemnity Agreement (Incorporated by reference from Exhibit 10.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.3†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan dated July 12, 2002 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.4	—	Agreement Regarding 2003 Registration Rights Agreement and Termination of Stockholders' Agreement, dated October 27, 2003 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.5†	—	Crosstex Energy, Inc. Long-Term Incentive Plan dated December 31, 2003 (incorporated by reference from Exhibit 10.5 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.6	—	Registration Rights Agreement, dated December 21, 2003 (incorporated by reference from Exhibit 10.6 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.7	—	Second Amended and Restated Credit Agreement dated November 26, 2002, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated reference from Exhibit 10.1 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.8	—	First Amendment to Second Amended and Restated Credit Agreement dated as of June 3, 2003, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference from Exhibit 10.2 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
10.9	—	Second Amendment to Second Amended and Restated Credit Agreement, dated as of June 3, 2003, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference from Exhibit 10.3 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50067).
10.10	—	Third Amendment to Second Amended and Restated Credit Agreement, dated as of April 1, 2004, by and among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference from Exhibit 10.1 to Crosstex Energy, LP.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
10.11	—	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of June 18, 2004, by and among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference from Exhibit 10.1 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, file No. 000-50067).
10.12	—	$50,000,000 Senior Secured Notes Master Shelf Agreement, dated as of June 3, 2003 (incorporated by reference from Exhibit 10.3 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
10.13	—	Letter Amendment No. 1 to Master Shelf Agreement, dated as of April 1, 2004, among Crosstex Energy Services, L.P., Prudential Investment Management, Inc., The Prudential Insurance Company of America and Pruco Life Insurance Company (incorporated by reference from Exhibit 10.2 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
10.14	—	Letter Amendment No. 2 to Master Shelf Agreement, dated as of June 18, 2004, among Crosstex Energy Services, L.P., Prudential Investment Management, Inc., The Prudential Insurance Company of America and Pruco Life Insurance Company (incorporated by reference from Exhibit 10.2 to Crosstex Energy, LP.'s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, file No. 000-50067).
10.15	—	First Contribution, Conveyance and Assumption Agreement dated November 27, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference from Exhibit 10.2 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).

Number		Description
10.16	—	Closing Contribution, Conveyance and Assumption Agreement dated December 11, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference from Exhibit 10.3 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.17†	—	Crosstex Energy Holdings Inc. 2000 Stock Option Plan (incorporated by reference from Exhibit 10.14 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
21.1*	—	List of Subsidiaries.
23.1*	—	Consent of KPMG LLP.
31.1*	—	Certification of the principal executive officer.
31.2*	—	Certification of the principal financial officer.
32.1*	—	Certification of the principal executive officer and the principal financial officer of the Company pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

† 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 Asset Management GP, LLC	Delaware
Crosstex Asset Management, L.P.	Delaware
Crosstex Holdings, L.P.	Delaware
Crosstex Holdings GP, LLC	Delaware
Crosstex Holdings LP, LLC	Delaware
Crosstex Energy GP, LLC	Delaware
Crosstex Energy GP, L.P.	Delaware
Crosstex Energy, L.P.	Delaware
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

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

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

We consent to the incorporation by reference in the registration statement (No. 333-114014) on Form S-8 of Crosstex Energy, Inc. of our reports dated March 14, 2005, with respect to the consolidated balance sheets of Crosstex Energy, Inc. as of December 31, 2004 and 2003, and the related consolidated statements of operations, changes in stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004, and all related financial statement schedules, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 and the effectiveness of internal control over financial reporting as of December 31, 2004, which reports appear herein.

KPMG LLP

Dallas, Texas
March 14, 2005

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy, Inc., certify that:

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

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 officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: March 14, 2005

/s/ BARRY E. DAVIS,

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

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, Executive Vice President and Chief Financial Officer of Crosstex Energy, Inc., certify that:

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

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 officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

(e) 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

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

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

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

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

Date: March 14, 2005

/s/ WILLIAM W. DAVIS

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

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, Inc. (the "Registrant") on Form 10-K for the year ended December 31, 2004 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 the Registrant, and William W. Davis, Chief Financial Officer of the Registrant, 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 result of operations of the Registrant.

Date: Mach 14, 2005

/s/ Barry E. Davis
Barry E. Davis
Chief Executive Officer

Date: Mach 14, 2005

/s/ William W. Davis
William W. Davis
Chief Executive Officer

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

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