# FORM 10-K/A

## CROSSTEX ENERGY INC - XTXI

**Filed: March 24, 2006 (period: December 31, 2005)**

Amendment to a previously filed 10-K

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# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# Form 10-K/A

**(Amendment No. 1)**

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended December 31, 2005**

**or**

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

**Commission file number: 000-50536**

# 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**<br>**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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☑

Indicate by check mark whether registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, as accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one).
Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $287,502,755 on June 30, 2005, based on $48.30 per share, the closing price of the Common Stock as reported on the NASDAQ National Market on such date.

At February 22, 2006, there were outstanding 12,763,469 shares of common stock.

**DOCUMENTS INCORPORATED BY REFERENCE:**

Portions of the Registrant's Proxy Statement relating to its 2006 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

## EXPLANATORY NOTE

On March 16, 2006, Crosstex Energy, Inc. filed with the Securities and Exchange Commission its Annual Report on Form 10-K for the fiscal year ended December 31, 2005 (the “Original Filing”). This Amendment No. 1 to the Original Filing has been filed solely to correct a typographical error appearing on page 1 in “Item 1. Business” and on page 29 in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” of the Original Filing. Crosstex Energy, Inc. has corrected such typographical error to disclose that it received $0.3 million in distributions pursuant to its 2% general partner interest in Crosstex Energy, L.P. instead of the $4.3 million reported in the Original Filing. In accordance with the rules of the Securities and Exchange Commission, this amendment sets forth the complete text of Items 1 and 7 as amended to correct this typographical error. This amendment does not update any disclosures to reflect developments since the filing date of the Original Filing. Except as discussed in this Explanatory Note, no other changes have been made to the Original Filing.

## 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 and natural gas liquids. These partnership interests consist of the following:

- 2,999,000 common units and 7,001,000 subordinated units, representing a 38% 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 $0.51 per unit for the quarter ended December 31, 2005. As a result, our distributions from the Partnership pursuant to our ownership of our 10,000,000 common and subordinated units have increased from $2.5 million for the quarter ended March 31, 2003 to $5.1 million for the quarter ended December 31, 2005; our distributions pursuant to our 2% general partner interest have increased from $74,000 to $0.3 million; and our distributions pursuant to our incentive distribution rights have increased from nothing to approximately $4.0 million. 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 $0.56 per share for the quarter ended December 31, 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 $530,000, and we would receive $365,000, or 69% 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 Partnership to finance all, or a portion of, such transactions, which may reduce or eliminate dividends paid to our stockholders.

## CROSSTEX ENERGY, L.P.

Crosstex Energy, L.P., is an independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas and NGLs. 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 NGLs, fractionates natural gas liquids into purity products and markets those products for a fee, 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. It operates processing plants that process gas transported to the plants by major interstate pipelines or from its own gathering systems under a variety of fee arrangements.

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

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

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

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

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

**Business Strategy**

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 and NGLs; 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. The Partnership will also build new assets in response to producer and market needs, such as the North Texas Pipeline project as discussed 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. For example, the Partnership believes the El Paso Acquisition complements its existing asset base in Louisiana and provides opportunities for asset optimization and cost-saving opportunities. 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. The Partnership 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. The Partnership established two new core areas through the acquisition and consolidation of its south Texas assets in 2000 through 2003, and the acquisition of the LIG Pipeline Company and its subsidiaries, which we collectively refer to as LIG, in 2004. The Partnership is now working to consolidate the El Paso Acquisition with LIG to develop operating synergies.

- *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. 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 which the Partnership believes provides a competitive advantage when competing for sources of natural gas supply. Since treating services are not provided by many competitors, the Partnership has 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 operating margins.

- *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. In 2005, the Partnership began construction on a new

143-mile pipeline to transport gas from an area near Fort Worth, Texas, where recent drilling activity in the Barnett Shale formation has expanded production beyond the existing infrastructure capability. The Partnership refers to this project as the North Texas Pipeline project and expects that it will commence operations in the first quarter of 2006. Once completed, the pipeline will allow curtailed gas to flow to markets that are currently not available to some key Barnett Shale producers. The Partnership is currently evaluating several similar projects in Texas and Louisiana.

**Recent Acquisitions and Expansion**

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

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

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

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

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

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

**Other Developments**

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

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

*November 2005 Public Offering.* In November and December 2005, CELP issued 3,731,050 common units to the public at a purchase price of $33.25 per unit. The offering resulted in net proceeds to the Partnership of approximately $120.9 million, including our $2.5 million capital contribution and after expenses associated with the offering. The net proceeds were used to fund a portion of the El Paso Acquisition.

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

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

**Midstream Segment**

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

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

  The primary facilities and other assets acquired consist of:

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

  - *Pelican Processing Plant.* The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. For the nine months ended

September 30, 2005 (prior to the acquisition and prior to the full impact of Hurricanes Rita and Katrina), the plant processed approximately 311 MMcf/d. In November and December 2005 (after the acquisition and the impacts of the hurricanes), the plant processed approximately 226 MMcf/d. The Pelican plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline.

- *Sabine Pass Processing Plant.* The Sabine Pas processing plant is located 15 miles east of the Sabine River at Johnson's Bayou, Louisiana and has a processing capacity of 300 MMcf/d of natural gas. The Sabine Pass plant is connected to continental shelf and deepwater gas production with downstream connections to Florida Gas Transmission, Tennessee Gas Pipeline and Transco. For the nine months ended September 30, 2005 (prior to the acquisition and prior to the full impact of Hurricanes Rita and Katrina), this facility processed approximately 235 MMcf/d. In November and December 2005 (after the acquisition and the impacts of the hurricanes), the plant processed approximately 125 MMcf/d.

- *Blue Water Gas Processing Plant.* CELP acquired a 23.85% interest in the Blue Water gas processing plant, which represents a net processing capacity to the acquired interest of 186 MMcf/d. Approximately 52 MMcf/d of the net capacity was being used in the nine months ended September 30, 2005 (prior to the acquisition and prior to the full impact of Hurricanes Rita and Katrina). In November and December 2005 (after the acquisition and the impacts of the hurricanes), approximately 21 MMcf/d was processed net to the interest. The Blue Water plant is located near Crowley, Louisiana and is operated by ExxonMobil. The Blue Water facility is connected to continental shelf and deepwater production volumes through the Blue Water pipeline system. Downstream connections from this plant include the Tennessee Gas Pipeline and Columbia Gulf. The facility also performs LNG conditioning services for the Excelerate Energy LNG tanker unloading facility.

- *Riverside Fractionation Plant.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of 28,000 to 30,000 barrels per day of liquids products and fractionates liquids delivered by the Cajun Sibon pipeline system from the Pelican, Blue Water and Cow Island plants or by truck. The Riverside facility has above-ground storage capacity of approximately 102,000 barrels.

- *Napoleonville Storage Facility.* The Napoleonville natural gas liquid storage facility is connected to the Riverside facility and has a total capacity of 2.4 million barrels of underground storage.

- *Cajun Sibon Pipeline System.* The Cajun Sibon pipeline system consists of 400 miles of 6-inch and 8-inch pipelines with a system capacity of 28,000 barrels per day. The pipeline transports raw make from the Pelican Complex and the Blue Water Plant to either the Riverside Fractionator or the Napoleonville storage facility. Alternate deliveries can be made to the Eunice Plant.

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

- *LIG System.* CELP acquired the LIG system on April 1, 2004. The LIG system is the largest intrastate pipeline system in Louisiana, consisting of 2,000 miles of gathering and transmission pipeline, and had an average throughput of approximately 613,000 MMBtu/d for the year ended December 31, 2005. The system also includes two operating processing plants with an average throughput of 300,000 MMBtu/d for the year ended December 31, 2005. The system has access to both rich and lean gas supplies. These supplies reach from north Louisiana to new offshore production in southeast Louisiana. LIG has a variety of transportation and industrial sales customers, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans.

- *South Texas System.* CELP has assembled a highly-integrated south Texas system comprised of approximately 1,400-miles of intrastate gathering and transmission pipelines and a processing plant with a processing capacity of approximately 150,000 mcf/d. This system was built through a number of acquisitions and follow-on organic projects. The acquisitions were the Gulf Coast system, the Corpus Christi system, the Gregory gathering system and processing plant, the Hallmark system, and the Vanderbilt system. Average throughput on the system for the year ended December 31, 2005 was approximately 517,000 MMBtu/d. Average throughput in the processing plant was approximately 95,000 MMBtu/d for that period. The system gathers gas from major production areas in the Texas Gulf coast and delivers gas to the industrial markets, power plants, other pipelines, and gas distribution companies in the region from Corpus Christi to the Houston area.

Other midstream assets and activities:

- *Mississippi Pipeline System.* This 603-mile system in south Mississippi gathers wellhead supply in the region and sells it through direct market connections to utilities and industrial end-users. Average throughput on the system was approximately 83,000 MMBtu/d for the year ended December 31, 2005.

- *Arkoma Gathering System.* This 140-mile low-pressure gathering system in southeastern Oklahoma delivers gathered gas into a mainline transmission system. For the year ended December 31, 2005, throughput on the system averaged approximately 23,000 MMBtu/d.

- *Other.* Other midstream assets consist of a variety of gathering lines and a processing plant with a processing capacity of approximately 65,000 Mcf/d. Total volumes gathered and resold were approximately 65,000 MMBtu/d for the year ended December 31, 2005. Total volumes processed were approximately 23,000 MMBtu/d in the period.

- *Off-System Services.* CELP offers natural gas marketing services on behalf of producers for natural gas that does not move on its assets. It markets this gas on a number of interstate and intrastate pipelines. These volumes averaged approximately 181,000 MMBtu/d in 2005.

**Treating Segment**

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 24% and 23% of the Partnership’s gross margin in 2005 and 2004, respectively. During 2005 the Partnership spent $16.0 million in two separate acquisitions to acquire 35 treating plants, 19 dewpoint control plants and related inventory. The treating business has grown from 74 plants in operation at December 31, 2004 to 112 plants in operation at December 31, 2005. In February 2006, CELP acquired the amine treating assets of a subsidiary of Hanover Compression Company, increasing total plants in operation to approximately 150 and its total fleet of treating plants to approximately 190.

CELP believes it has the largest gas treating operation in the Texas and Louisiana Gulf Coast. The treating plants remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced to transportation systems to ensure that it meets pipeline quality specifications. Natural gas from certain formations in the Texas Gulf Coast, as well as other locations, is high in carbon dioxide. Many of the Partnership’s 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 the Partnership to operate the treating facilities, it either charges a fixed rate per Mcf of natural gas treated or charges a fixed monthly fee.

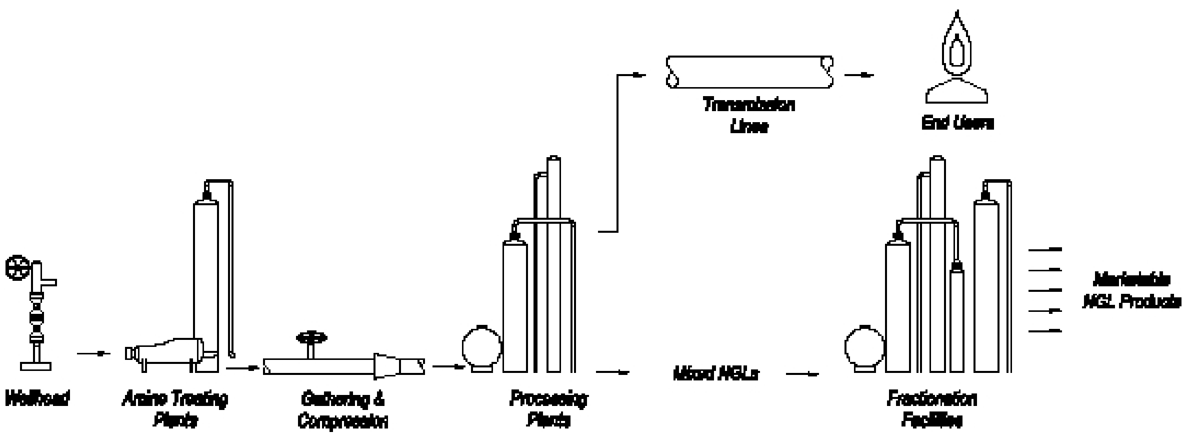
CELP also owns an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas, and which is accounted for as part of the Treating Division. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon 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 at recent levels, producers will be encouraged to drill deeper gas formations. We believe the gas recovered from these formations is more likely to be high in carbon dioxide, a contaminant that generally needs to be removed before introduction into transportation pipelines. When completing a well, producers place a high value on immediate equipment availability, as they can more quickly begin to realize cash flow from a completed well. 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 remove the impurities from the gas. After mixing, gas and reacted amine are separated and the impurities are removed from the amine by heating. Treating plants are sized by the amine circulation capacity in terms of gallons per minute.

**Industry Overview**

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




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

*Natural gas gathering.* The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. 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. Most treating plants and transmission pipelines 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, processing plants, and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

**Supply/Demand Balancing**

As CELP purchases natural gas, it normally establishes a margin by selling natural gas for physical delivery to third-party users. CELP can also use over-the-counter derivative instruments or enter into a future delivery obligation under futures contracts on the New York Mercantile Exchange. Through these transactions, CELP 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. CELP's policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

**Competition**

The business of providing natural gas gathering, transmission, treating, processing and marketing services for natural gas and NGLs is highly competitive. CELP faces strong competition in acquiring new natural gas supplies. CELP's 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 CELP's competitors offer more services or have greater financial resources and access to larger natural gas supplies than it does. CELP's competition will likely differ in different geographic areas.

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

In marketing natural gas and NGLs, 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.

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

**Natural Gas Supply**

CELP's transmission pipelines have connections with major interstate and intrastate pipelines, which it believes have ample supplies of natural gas in excess of the volumes required for these systems. In connection with the construction and acquisition of 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. CELP does not routinely obtain independent evaluations of reserves dedicated to its systems due to the cost and relatively limited benefit of such evaluations. Accordingly, CELP 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 it issues 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, 2005, CELP had one customer that individually accounted for approximately 10.6% of consolidated revenues. While this customer represents a significant percentage of consolidated revenues, the loss of this customer would not have a material impact on our results of operations.

**Regulation**

*Regulation by FERC of Interstate Natural Gas Pipelines.* CELP does not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission ("FERC") does not directly regulate its operations under the National Gas Act ("NGA"). However, FERC's regulation of interstate natural gas pipelines 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. The Partnership's intrastate natural gas pipeline operations generally are not subject to rate regulation by FERC, but the rates, terms and conditions of service under which it transports natural gas in their pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). Rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate", as defined in the NGPA. The rates are generally subject to review every three years by the FERC or by an appropriate state agency. Rates for interstate services provided under NGPA Section 311 on our Louisiana and Mississippi pipeline systems are each subject to review in 2006.

*Intrastate Pipeline Regulation.* 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. 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 they charge for transportation services are deemed just and reasonable under Texas law unless challenged in a complaint. We cannot predict whether such a complaint will be filed against the Partnership 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 CELP's Mississippi gathering system is regulated by the Mississippi Oil and Gas Board as it transports gas not owned by them for a fee. The Arkoma gathering system in Oklahoma is regulated by the Oklahoma Corporation Commission. Similarly, gathering systems owned by the Partnership in Alabama are subject to regulation by the Alabama State Oil and Gas Board. CELP's 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 the Partnership's gathering facilities are subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

The Partnership 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. Their 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 the Partnership'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 the Partnership sells natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The Partnership's 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 the Partnership will be affected by any such FERC action materially differently than other natural gas marketers with whom they compete.

**Environmental Matters**

*General.* CELP's operation of treating, processing and fractionation plants, pipelines and associated facilities in connection with the gathering, treating and processing of natural gas and the transportation, fractionation and storage of NGLs is subject to stringent and complex federal, state and local laws and regulations relating to release of hazardous substances or wastes into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall costs of doing business, including cost of planning, constructing, and operating plants, pipelines, and other facilities. Included in CELP's construction and operation costs are capital cost items necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to obtaining required governmental approvals, may result in the assessment of administrative, civil, or criminal penalties, imposition of investigatory or remedial activities and, in less common circumstances, issuance of injunctions or construction bans or delays. While we believe that CELP currently holds all material governmental approvals required to operate our major facilities, we are currently evaluating and updating permits for certain of our facilities specifically including those obtained in recent acquisitions. As part of the regular overall evaluation of our operations, CELP has implemented procedures and are presently working to ensure that all governmental approvals, for both recently acquired facilities and existing operations, are updated as may be necessary. We believe that 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 its operating results or financial condition.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with CELP's possible future operations, and we cannot assure you that CELP 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, CELP 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 CELP 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 to comply with changing environmental laws and regulations and to minimize costs.

*Hazardous Substance and Waste.* To a large extent, the environmental laws and regulations affecting the Partnership's 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. The Partnership 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. The Partnership is not currently required to comply with a substantial portion of the RCRA requirements because its operations generate minimal quantities of hazardous wastes. However, it is possible that some wastes generated by CELP that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements. Changes in applicable regulations may result in an increase in CELP's 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, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom 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, CELP 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.

The Partnership acquired the south Louisiana processing assets from the El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality ("LDEQ") based on the Risk-Evaluation and Corrective Action Plan Program ("RECAP") rules. In addition, CELP is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. The estimated remediation costs are expected to be approximately $0.3 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to CELP's ownership, these costs were accrued as part of the purchase price.

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

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

*Air Emissions.* The Partnership's current and 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 CELP's operations, could cause capital expenditures to be incurred in the next several years for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission related issues. In addition, the 1990 Clean Air Act Amendments established a new operating permit for major sources, which applies to some of the facilities and which may apply to some of CELP's possible future facilities. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties, and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe implementation of the 1990 Clean Air Act Amendments will not have a material adverse effect on our financial condition or operating results.

*Clean Water Act.* The Federal Water Pollution Control Act, also known as the Clean Water Act, and similar state laws impose restrictions and strict controls regarding the discharge of pollutants, including natural gas liquid related wastes, into state waters or waters of the United States. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System, or NPDES, and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. CELP believes that it is in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that continued compliance with such existing permit conditions will not have a material effect on 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. CELP believes that its operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

*Safety Regulations.* CELP's pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, as amended, or HLPSA, and the Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192, effective February 14, 2004 relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA covers crude oil, carbon dioxide, NGL and petroleum products pipelines and requires any entity which owns or operates pipeline facilities to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. The Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192 (PIM) requires operators of gas transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. In addition, the TRRC regulates CELP's pipelines in Texas under its own pipeline integrity management rules. The Texas rule includes certain transmission and gathering lines based upon pipeline diameter and operating pressures. CELP believes that its pipeline operations are in substantial compliance with applicable HLPSA and PIM requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the HLPSA or PIM requirements will not have a material adverse effect on our results of operations or financial positions.

**Employees**

As of December 31, 2005, the Partnership had approximately 496 full-time employees. Approximately 218 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.

## PART II

### 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 and NGLs. 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 and NGLs. These partnership interests consist of (i) 2,999,000 common units and 7,001,000 subordinated units, representing approximately 38% 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 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 $0.51 per unit for the quarter ended December 31, 2005. As a result, our distributions from the Partnership pursuant to our ownership of our 10,000,000 common and subordinated units have increased from $2.5 million for the quarter ended March 31, 2003 to $5.1 million for the quarter ended December 31, 2005; our distributions pursuant to our 2% general partner interest have increased from $74,000 to approximately $0.3 million; and our distributions pursuant to our incentive distribution rights have increased from nothing to $4.0 million. 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 $0.56 per share for the quarter ended December 31, 2005.

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 Texas Gulf Coast and in Mississippi and Louisiana. The Partnership's Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, while the Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the year ended December 31, 2005, 76% of our gross margin was generated in the Midstream division, with the balance in the Treating division. 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 or NGLs 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 formation of the Partnership's predecessor, 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, 2005, the Partnership has invested over $973 million to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

The Partnership's midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through its pipeline systems, processed at its processing facilities and the volumes of natural gas liquids handled at its fractionation facilities. Treating segment margins are largely a function of the number and size of treating plants as well as fees earned for removing impurities and from natural gas liquids at a non-operated processing plant. CELP 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 and fractionating and marketing the recovered natural gas liquids;
- treating natural gas at its treating plants;
- recovering carbon dioxide and natural gas liquids at a non-operated processing plant; and
- providing off-system marketing services for producers.

The bulk of 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 it 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.

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

The Partnership generates treating revenues under three arrangements:

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

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

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, 2003, are the acquisitions of the DEFS assets, the LIG assets, and the El Paso processing and liquids business in south Louisiana. It also acquired treating operations totaling $16.0 million in 2005.

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

On January 2, 2005 the Partnership acquired all of the assets of Graco Operations for $9.26 million. Graco's assets consisted of 26 treating plants and associated inventory. On May 1, 2005 it acquired all of the assets of

Cardinal Gas Services for $6.7 million. Cardinal's assets consisted of nine gas treating plants, 19 operating wellhead gas processing plants for dewpoint suppression, and equipment inventory.

In April 2004 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, including three idle plants that straddle the pipeline in three locations and have a total processing capacity 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. It subsequently sold one of the idle plants with a capacity of 225,000 MMBtu/d in September 2005 and realized a gain on sale of $8.0 million.

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.

*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 has 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 of $33.6 million as of December 31, 2005 for federal income taxes and state loss carryforwards of $7.3 million. We estimate that our net operating loss carryforwards will be utilized to offset federal taxable income in 2006 and 2007. In years after 2007, 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 crude oil, NGL products and natural gas.

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 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, 2005.

| | Year ended December 31, 2005 | | | |
|---|---|---|---|---|
| | Gas Purchased | | Gas Sold | |
| Asset or Business | Fixed Amount to Index | Percentage of Index | Fixed Amount to Index | Percentage of Index |
| | (In thousands of MMBtu's) | | | |
| LIG system | 119,061 | 6,442 | 125,503 | — |
| South Texas system(1) | 161,613 | 21,092 | 167,292 | — |
| Other assets and activities | 101,932 | 3,533 | 105,466 | — |

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

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 hedge positions). As of December 31, 2005, it has hedged approximately 78% of its exposure to such fluctuations in natural gas prices for 2006. CELP expects to continue to hedge its exposure to gas prices when market opportunities appear attractive.

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

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.

For the year ended December 31, 2005, the Partnership purchased a small amount (approximately 5.5%) 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 94.5% 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 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 for each Mcf of carbon dioxide returned to the producer for reinjection. 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 2005, its share of NGLs totaled 5.9 million gallons at an average price of $0.91 per gallon. The Partnership executed forward sales on approximately 80% of its anticipated 2006 share of NGLs.

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

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

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

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

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

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

*Operating Expenses.* Operating expenses were $56.8 million for the year ended December 31, 2005 compared to $38.4 million for the year ended December 31, 2004, an increase of $18.4 million, or 48%. An increase of $5.3 million was associated with the acquisition of the El Paso assets. Increases of $4.6 million were associated with the acquisition of the LIG assets as they were owned for the entire year instead of nine months in 2004. Midstream operating expenses also increased by $2.6 million due to small acquisitions and expansions of systems and the addition of compressors or other rental services. The growth in treating plants in service due to acquisition of the Graco assets and the Cardinal assets as well as internal growth increased operating expenses by $5.2 million. Operations expense includes stock-based compensation expense of $0.4 million and $0.2 million in 2005 and 2004, respectively.

*General and Administrative Expenses.* General and administrative expenses were $34.1 million for the year ended December 31, 2005, compared to $22.0 million for the year ended December 31, 2004, an increase of $12.1 million, or 55%. A significant contributor was additional staffing-related costs, an incremental $6.0 million over 2004. The staff additions required to manage and optimize our acquisitions account for the majority of the change, although a number of leadership and strategic positions were added that will allow us to absorb future growth more efficiently. Other expenses related to growth, including office rent, utilities, and travel expenses, account for $2.6 million of the increase. General and administrative expense includes stock-based compensation expense of $3.7 million in 2005 and $0.8 million in 2004. The increase in stock-based compensation primarily relates to restricted stock and unit grants and $0.4 million in accelerated options.

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

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

*Depreciation and Amortization.* Depreciation and amortization expenses were $36.1 million for the year ended December 31, 2005 compared to $23.0 million for the year ended December 31, 2004, an increase of $13.1 million, or 57%. Of the increase, the acquisition of the El Paso assets contributed $5.5 million and the LIG assets contributed $1.3 million. New treating plants placed in service resulted in an increase of $2.3 million. The remaining $3.9 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Dallas office, computer software and equipment, and expansions on midstream assets.

*Interest Expense.* Interest expense was $15.3 million for the year ended December 31, 2005 compared to $9.1 million for the year ended December 31, 2004, an increase of $6.2 million, or 68%. The increase relates primarily to an increase in average debt outstanding. Average higher interest rates also increased from 2004 to 2005 (weighted average rate of 6.1% in 2004 compared to 6.3% in 2005).

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

*Gain on Issuance of Units of the Partnership.* As a result of the Partnership issuing additional units in November 2005 at a price per unit greater than our equivalent carrying value, our share of the net assets in the Partnership increased by $65.1 million. Accordingly, we recognized a $65.1 million gain in 2005.

*Income Tax Expense.* We provide for income taxes using the asset and 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 $30.0 million in 2005 compared to $5.1 million in 2004, an increase of $25.0 million. The increase in the tax provision was primarily due to the taxes provided on the $65.1 million gain on issuance of units of the Partnership during 2005.

*Interest of Non-controlling Partners in the Partnership's Net Income.* The interest of non-controlling partners in the Partnership's net income decreased by $3.6 million to $4.7 million for the year ended December 31, 2005 compared to $8.2 million for the year ended December 31, 2004. The Partnership's net income decreased from $23.7 million in 2004 to $19.2 million in 2005 contributing to the decrease in the interest of non-controlling partners. The non-controlling partners share of the Partnership net income was further reduced by the increase in net income allocated to us for our incentive distributions which increased from $5.6 million in the year ended December 31, 2004 to $10.7 million in the year ended December 31, 2005. Income from the Partnership is allocated to us for our incentive distributions less stock-based compensation attributable to our options and restricted units with the remaining income being allocated pro rata to the 2% general partner interest and the common units and subordinated units (excluding senior subordinated units). Distributions from the Partnership will generally be made 98% to the common and subordinated unitholders (other than the senior subordinated unitholders) and 2% to the Company as the general partner, subject to the payment of incentive distributions to the extent that certain target levels of cash distributions are achieved. Under the quarterly incentive distribution provisions, generally the Company 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.

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

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

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

*Operating Expenses.* Operating expenses were $38.4 million for the year ended December 31, 2004 compared to $19.9 million for the year ended December 31, 2003, an increase of $18.5 million, or 93%. Increases of $3.5 million and $9.5 million were associated with the acquisition of the DEFS and LIG assets, respectively. General operations expense (expenses not directly related to specific assets) was $6.0 million for 2004 compared to $1.7 million for 2003. The majority of the $4.3 million increase was related to higher technical services support required by the newly-acquired assets and additional expenditures related to our pipeline integrity program. The growth in treating plants in service increased operating expenses by $1.2 million. Stock-based compensation expense included in operating expenses included $0.2 million and $2.1 million in 2004 and 2003, respectively. During 2003, certain 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.

*General and Administrative Expenses.* General and administrative expenses were $22.0 million for the year ended December 31, 2004 compared to $14.8 million for the year ended December 31, 2003, an increase of $7.2 million, or 49%. A significant part of the increased expenses was $5.0 million of additional staffing related costs. The staff additions required to manage and optimize our LIG and DEFS acquisitions account for the majority of the change, although a number of leadership and strategic positions were added that will allow us to absorb future growth more efficiently. Consistent with staffing for future growth, an additional $1.0 million in consulting costs were made to upgrade our systems, providing a more scalable infrastructure. Sarbanes Oxley compliance costs were an additional $1.1 million for 2004 compared to zero in 2003. Other expenses, including audit and tax fees, office rent, K-1 preparation fees and travel expenses, account for $1.7 million of the increase. Stock-based compensation included in general and administrative expenses was $0.8 million and $3.2 million in 2004 and 2003, respectively. During 2003, certain 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 $1.0 million 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 of 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.

*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 $1.4 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Gregory Plant and the consolidation of Denton County assets.

*Interest Expense.* Interest expense was $9.1 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 interest rates also increased from 2003 to 2004 (weighted average rate of 6.1% in 2004 compared to 5.4% in 2003).

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

*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 increased from $1 million for the year ended December 31, 2003 to $5.6 million 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.

*Income Tax Expense.* Income tax expense was $5.1 million for the year ended December 31, 2004 compared to $10.1 million for the year ended December 31, 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.

**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.

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

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

The Partnership manages its price risk related to future physical purchase or sale commitments for its Commercial Services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance 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's energy trading contracts qualify as derivatives under SFAS No. 133, and accordingly, the Partnership continues to use mark-to-market accounting for both physical and financial contracts of its Commercial Services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Partnership's Commercial Services natural gas marketing activities are recognized in earnings as profit or loss on energy trading immediately.

For each reporting period, the Partnership records the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period in addition to the 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 $12.8 million for the year ended December 31, 2005 compared to cash provided by operations of $46.3 million for the year ended December 31, 2004. Income before non-cash income and expenses was $61.7 million in 2005 and $47.2 million in 2004. Changes in working capital used $48.9 million in cash flows from operating activities in 2005 and provided $.8 million in cash flows from operating activities in 2004. Income before non-cash income and expenses increased between years primarily due to asset acquisitions as discussed in "Results of Operations — Year Ended December 31, 2005 Compared to Year Ended December 31, 2004." Changes in working capital are primarily due to the timing of collections at the end of the quarterly periods. 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. Increased natural gas and natural gas liquids prices together with the acquisition of the El Paso assets contributed to increases in accounts receivable, accrued gas sales, accounts payable, accrued gas purchases, imbalance receivables and payables and inventory costs during 2005.

Net cash used in investing activities was $614.8 million and $124.4 million for the year ended December 31, 2005 and 2004, respectively. Net cash used in investing activities during 2005 related to the El Paso assets ($489.4 million), the Graco assets ($9.3 million), and the Cardinal assets ($6.7 million). The remaining cash used in investing activities for 2005 relates to internal growth projects including expenditures of the North Texas Pipeline ("NTPL") project of approximately $80.0 million, $22.9 million for buying, refurbishing and installing treating plants and $18.3 million for expansions, well connections and other capital projects on the pipeline, gathering and processing assets. Net cash used in investing activities during 2004 related to the LIG acquisition ($73.7 million) and the purchase of the outside partner interests in Crosstex Pipeline Partners ($5.1 million) as well as internal growth projects. The primary internal growth projects during 2004 were buying, refurbishing and installing treating plants ($24.5 million).

Net cash provided by financing activities was $592.4 million and $99.1 million for the years ended December 31, 2005 and 2004, respectively. Financing activities in 2005 relate to proceeds from the sale of common units and subordinated units discussed below and increased borrowings under the Partnership's credit facility. Financing activities for 2005 relate primarily to funding the acquisitions of the El Paso assets, Graco assets, Cardinal assets and to funding the NTPL project. Financing activities for 2004 relate primarily to funding the LIG acquisition. Distributions to partners of CELP totaled $43.3 million in 2005 compared to distributions of $34.3 million in 2004 due to increases in the distribution levels between years, including incentive distributions. Drafts payable decreased by $8.8 million requiring the use of cash in 2005 compared to an increase in drafts payable of $28.2 million providing cash from financing activities in 2004. In order to reduce our interest costs, we borrow money to fund outstanding checks as they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility.

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

*June 2005 Sale of Senior Subordinated Units.* In June 2005, CELP issued 1,495,410 senior subordinated units in a private offering for net proceeds of $50.0 million, excluding our $1.1 million general partner contribution and after expenses associated with the sale. The senior subordinated units were issued at $33.44 per unit, which represents a discount of 13.7% to the market value of common units on such date, and automatically converted to common units on a one-for-one basis on February 24, 2006. The senior subordinated units were not entitled to distributions of available cash until they converted to common units.

*November 2005 Sale of Senior Subordinated B Units.* On November 1, 2005, CELP issued 2,850,165 Senior Subordinated Series B Units in a private placement for a purchase price of $36.84 per unit. CELP received net proceeds of approximately $105.0 million, excluding our $2.1 million general partner contribution and after expenses associated with the sale. The Senior Subordinated Series B Units automatically converted into common units on November 14, 2005 at a ratio of one common unit for each Senior Subordinated Series B Units and were not entitled to distributions paid on November 14, 2005.

*November 2005 Public Offering.* In November and December 2005, CELP issued 3,731,050 common units to the public at a purchase price of $33.25 per unit. The offering resulted in net proceeds to the Partnership of $118.4 million, excluding our $2.5 million general partner contribution and after expenses associated with the offering.

*Senior Secured Notes.* In November 2005, CELP completed a private placement of $85.0 million of senior secured notes pursuant to the master shelf agreement with an institutional lender with an interest rate of 6.23% and a maturity of ten years.

*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 $12.9 million cash on hand at December 31, 2005, 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 and large capital expansions, it anticipates that it will continue to invest significant amounts of capital to grow and to build and acquire assets. The Partnership actively considers a variety of assets for potential development or acquisition.

The Partnership believes that cash generated from operations will be sufficient to meet its present quarterly distribution level of $0.51 per quarter and to fund a portion of its anticipated capital expenditures through December 31, 2006. Total capital expenditures are budgeted to be approximately $120 million in 2006. The Partnership expects to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below and with 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, 2005, is as follows:

| | Payments due by period | | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2006 | 2007 | 2008 | 2009 | 2010 | Thereafter |
| | | | | (In millions) | | | |
| Long-Term Debt | $ 522.6 | $ 6.5 | $ 10.0 | $ 9.4 | $ 9.4 | $ 342.3 | $ 145.0 |
| Capital Lease Obligations | — | — | — | — | — | — | — |
| Operating Leases | 94.1 | 14.6 | 14.4 | 14.1 | 13.8 | 13.5 | 23.7 |
| Unconditional Purchase Obligations | 14.1 | 14.1 | — | — | — | — | — |
| Other Long-Term Obligations | — | — | — | — | — | — | — |
| Total Contractual Obligations | $ 630.8 | $ 35.2 | $ 24.4 | $ 23.6 | $ 23.2 | $ 355.8 | $ 168.7 |

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

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

**Description of Indebtedness**

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

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

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

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

The obligations under the bank credit facility are secured by first priority liens on all of the Partnership's material pipeline, gas gathering, treating, 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 certain of the Partnership's subsidiaries. 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 credit facility bears interest at the Partnership's option at the administrative agent's reference rate plus 0.0% to 0.50% or LIBOR plus 1.00% to 2.00%. The applicable margin varies quarterly based on the Partnership's leverage ratio. The fees charged for letters of credit range from 1.00% to 2.00% per annum, plus a fronting fee of 0.125% per annum. 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 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, limits the Partnership's ability and the ability of its subsidiaries to:

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;

- make distributions;
- change the nature of its business;
- enter into certain commodity contracts;
- make certain amendments to its or the Operating Partnership's partnership agreement; and
- engage in transactions with affiliates.

The credit facility also adjusted financial covenants requiring the Partnership to maintain:

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

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

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

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

The notes represent the Partnership's senior secured obligations and rank at least *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with the Partnership's obligations 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 its equity interests in certain of its subsidiaries. The senior secured notes are guaranteed by the Partnership's significant 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 and the $85.0 million issued in November 2005 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance.

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

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

The Partnership was in compliance with all debt covenants at December 31, 2005 and 2004 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 our operating partnership and its subsidiaries. As amended in 2005, this agreement appoints Bank of America to act as collateral agent and authorized the bank to execute various security documents on behalf of the lenders under the bank credit facility and the initial purchases of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing Crosstex Energy Services, L.P.'s obligations under the bank credit facility and the master shelf agreement.

**Inflation**

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2003, 2004 or 2005. Although the impact of inflation has 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 — Crosstex Energy, L.P. — Environmental Matters."

**Recent Accounting Pronouncements**

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

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

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

**Disclosure Regarding Forward-Looking Statements**

This report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "forecast," "may, ""believe, ""will, ""expect, ""anticipate, ""estimate, ""continue" or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. We have identified factors that could cause actual plans or results to differ materially from those included in any forward-looking statements. These factors include those described in "Item 1A. Risk Factors", or in our other Securities and Exchange Commission filings, among others. Such risks and uncertainties are beyond our ability to control, and in many cases, we cannot predict the risks and uncertainties that could cause our actual results to differ materially from those indicated by the forward-looking statements. You should consider these risks when you are evaluating us.

We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

# PART IV

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

The following documents are filed as part of this report:

(a) *Financial Statements and Schedules*

(3) *Exhibits.*

The exhibits filed as part of this Form 10-K/A are as follows:

| Number | | Description |
|---|---|---|
| 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.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Form 10-K/A to be signed on its behalf by the undersigned, thereunto duly authorized, on the 24th day of March 2006.

CROSSTEX ENERGY, INC.

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

## EXHIBIT INDEX

| Number | | Description |
|---|---|---|
| 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.

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

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

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

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

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

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

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

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

/s/ BARRY E. DAVIS

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

Date: March 24, 2006

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

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

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

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

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

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

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

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

/s/ WILLIAM W. DAVIS

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

Date: March 24, 2006

**Exhibit 32.1**

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

In connection with the Annual Report of Crosstex Energy, Inc. (the "Registrant") on Form 10-K/A for the year ended December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the Registrant, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner 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.

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| Date: March 24, 2006 | /s/ BARRY E. DAVIS |
| | Barry E. Davis<br>*Chief Executive Officer* |
| Date: March 24, 2006 | /s/ WILLIAM W. DAVIS |
| | William W. Davis<br>*Chief Financial 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.