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FILE PURSUANT TO RULE 424(b)(4)
REGISTRATION NO. 333-106927

PROSPECTUS

1,500,000 Common Units

Crosstex Energy, L.P.

Representing Limited Partner Interests

We are offering 1,500,000 common units representing limited partner interests. Our common units are traded on the Nasdaq National Market under the symbol "XTEX." On September 3, 2003, the last reported sale price of our common units on the Nasdaq National Market was $35.97 per common unit.

Investing in our common units involves risk.
See "Risk Factors" beginning on page 16.

These risks include the following:

- We may not have sufficient cash to pay the minimum quarterly distribution each quarter.
- We must continually compete for natural gas supplies, and any decrease in our supplies of natural gas could reduce our ability to make distributions to our unitholders.
- Our profitability is dependent upon prices and market demand for natural gas and natural gas liquids, or NGLs, which are beyond our control and have been volatile.
- If we are unable to integrate our recent acquisitions or if we do not continue to make acquisitions on economically acceptable terms, our future financial performance may be limited.
- We may not be able to retain existing customers or acquire new customers, which would reduce our revenues and limit our future profitability.
- Due to our lack of asset diversification, adverse developments in our gathering, transmission, treating, processing and producer services businesses would reduce our ability to make distributions to our unitholders.
- Our general partner has sole responsibility for conducting our business and managing our operations. Our general partner will be entitled to be reimbursed for all direct and indirect expenses it incurs on our behalf, which may be substantial and will reduce our ability to make distributions to unitholders.
- Crosstex Energy Holdings Inc. controls our general partner and will own a 56% limited partner interest in us after the offering. Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor its own interests to the detriment of our unitholders.
- Our unitholders will have no right to elect our general partner or the directors of its general partner and will have limited ability to remove our general partner.
- Our common units have a limited trading history and a limited trading volume compared to other units representing limited partner interests.
- You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

PRICE $35.97 PER COMMON UNIT

	Per Common Unit	Total
Public offering price	$ 35.970	$ 53,955,000
Underwriting discount	$ 1.888	$ 2,832,000
Proceeds, before expenses, to Crosstex Energy, L.P.	$ 34.082	$ 51,123,000

We have granted the underwriters a 30-day option to purchase up to an additional 225,000 common units to cover over-allotments. The underwriters expect to deliver the common units to purchasers on or about September 8, 2003.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

A.G. Edwards & Sons, Inc.

RBC Capital Markets

Raymond James

Prospectus dated September 3, 2003

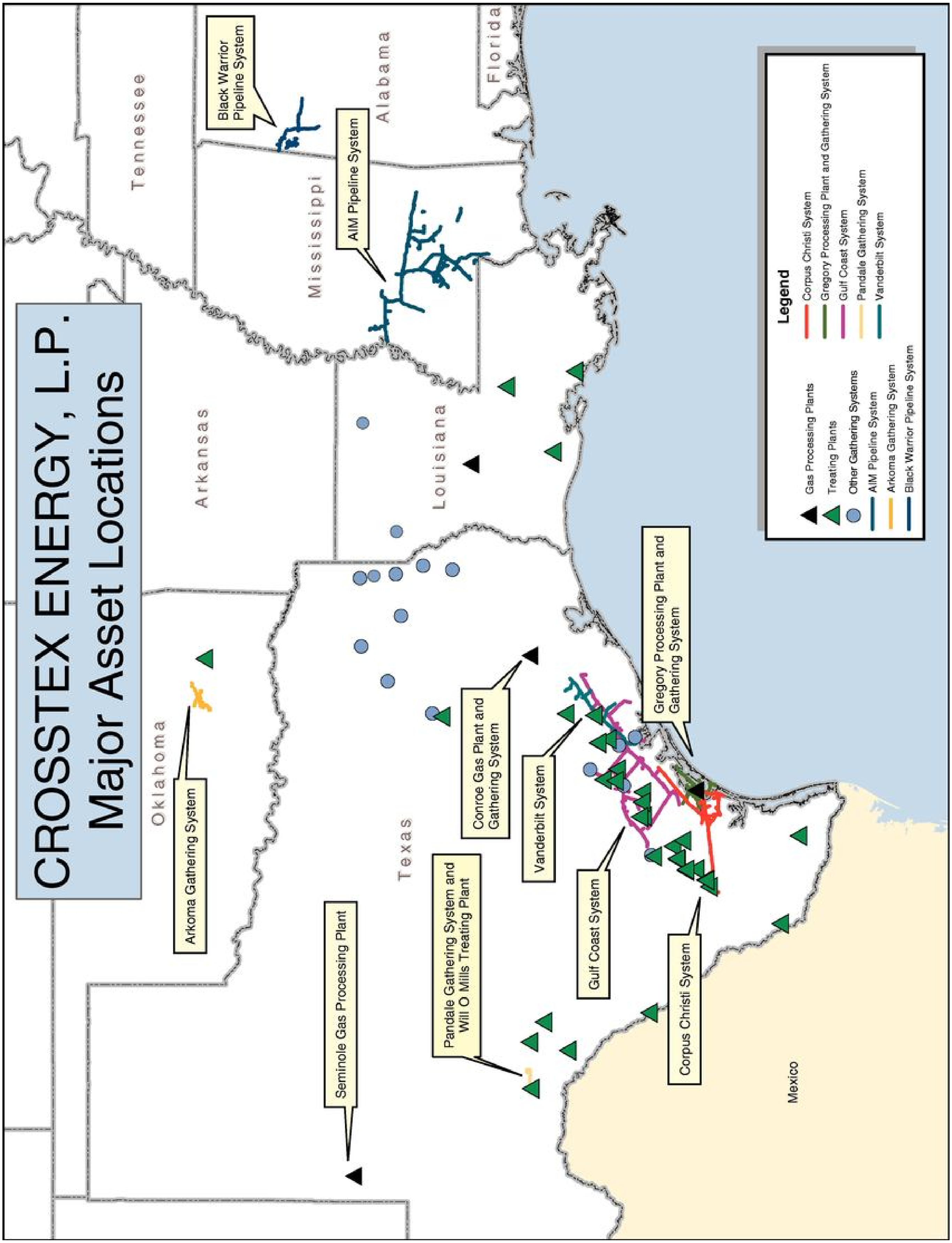


TABLE OF CONTENTS

PROSPECTUS SUMMARY

The summary highlights selected information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the historical and pro forma financial statements and notes to those financial statements. The information presented in this prospectus assumes that the underwriters' over-allotment option is not exercised. You should read "Summary of Risk Factors" beginning on page 3 and "Risk Factors" beginning on page 16 for more information about important factors that you should consider before buying common units. We have included a "Glossary of Terms" as Appendix A that defines many of the terms we use in this prospectus.

References in this prospectus to "Crosstex Energy, L.P.," "we," "ours," "us," or like terms when used in the present tense or prospectively or for historical periods since December 2002 refer to Crosstex Energy, L.P. and its operating subsidiaries. Crosstex Energy, L.P. is the issuer of securities in this offering. References to "our predecessor" or to "we," "ours," "us," or like terms for historical periods prior to December 2002 refer to Crosstex Energy Services, Ltd. Substantially all of the assets of Crosstex Energy Services, Ltd. were transferred to us at the closing of our initial public offering in December 2002.

Crosstex Energy, L.P.

Overview

We are a rapidly growing independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas. We connect the wells of natural gas producers in our market areas to our gathering systems, treat natural gas to remove impurities to ensure that it meets pipeline quality specifications, process natural gas for the removal of natural gas liquids, or NGLs, transport natural gas and ultimately provide an aggregated supply of natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipelines and thereby generate gross margins based on the difference between the purchase and resale prices. In addition, we purchase natural gas from producers not connected to our gathering systems for resale and sell natural gas on behalf of producers for a fee.

We have grown rapidly since the inception of our various predecessors in 1992 through a combination of acquisitions and the construction of new assets. Since January 2000, we have acquired and integrated 13 operations with an aggregate purchase price of approximately $142.3 million, including our recent $67.3 million acquisition of assets from Duke Energy Field Services, L.P., which we refer to in this prospectus as DEFS. Our net income increased to $2.0 million for the year ended December 31, 2002, compared to a net loss of $0.5 million for the year ended December 31, 1998. Our net income was $5.8 million for the six months ended June 30, 2003. Our gross margin increased to $32.7 million for the year ended December 31, 2002, compared to $2.2 million for the year ended December 31, 1998. Our gross margin was $23.9 million for the six months ended June 30, 2003.

We have two operating divisions, the Midstream division, which consists of our natural gas gathering, transmission, processing, marketing and producer services operations, and the Treating division, which provides natural gas treating for the removal of carbon dioxide and other contaminants. Our primary Midstream assets include systems located along the Texas Gulf Coast and in south-central Mississippi, and, in the aggregate, consist of approximately 2,500 miles of gathering and transmission pipelines, and three natural gas processing plants. After giving pro forma effect to our recent acquisition of assets from DEFS, for the year ended December 31, 2002 and the six months ended June 30, 2003, we would have gathered and transported approximately 501,233 MMBtu/d and 603,160 MMBtu/d of natural gas, respectively. In our producer services operations, we purchase for resale volumes of natural gas that do not move through our gathering, processing or transmission assets from over 50 independent producers. Our treating plants remove carbon dioxide and hydrogen sulfide from

natural gas before it is delivered into transportation systems to ensure that the natural gas meets pipeline quality specifications.

Recent Developments

Recent Acquisitions

Duke Energy Field Services. In June 2003, we acquired various midstream assets located in Mississippi, Texas, Alabama and Louisiana from DEFS for $67.3 million in cash. The principal assets we acquired were the AIM pipeline system, a 638-mile natural gas gathering and transmission system in 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. In addition, we acquired the Conroe gas plant and gathering system north of Houston, the Black Warrior gathering pipeline system in Alabama and two small gathering systems in Louisiana. This acquisition has provided us with a new core area for growth in south-central Mississippi, expanded our presence in West Texas, increased the total miles of our pipelines from 1,700 to 2,500 and enabled us to enter the business of carbon dioxide separation. In addition, the acquisition should increase the stability of our cash flow as operating profits from the AIM pipeline system are generated through purchasing, gathering, transporting and reselling natural gas which generates margins not affected by commodity prices, and a majority of the income we receive from the Seminole gas plant is based on fixed fees for carbon dioxide separation and sulfur removal. Average throughput on the AIM pipeline system at the time of acquisition was approximately 84,000 MMBtu/d.

Vanderbilt System. In December 2002, we acquired the Vanderbilt system from a subsidiary of Devon Energy Corporation for $12.0 million. The Vanderbilt system consists of approximately 200 miles of gathering pipeline located near our Gulf Coast system. The system's gathering pipeline ranges in diameter from four to 14 inches and has a capacity of 130,000 Mcf/d. Average throughput on the system was approximately 40,850 MMBtu/d for the six months ended June 30, 2003. Gathered natural gas currently flows to the Formosa Hydrocarbons processing plant at Point Comfort, Texas.

Will-O-Mills. In December 2002, we consolidated our ownership of the Will-O-Mills treating plant by purchasing the remaining 50% operating interest we did not own for $2.2 million. The consolidation of the Will-O-Mills interest enabled us to negotiate the closure of another plant in the area and transfer those volumes to Will-O-Mills, resulting in an approximate 30% increase in cash flow from the plant. In addition, we are able to utilize Will-O-Mills direct labor capacity to more efficiently manage other company assets in the area.

Recent Expansion and Construction

Gregory Expansion. We are nearing completion of an expansion of our Gregory processing plant. The expansion will increase the plant capacity from approximately 90,000 Mcf/d to 150,000 Mcf/d and will cost approximately $8.0 million. We expect to complete this expansion in August 2003. In addition, we have significantly reduced our exposure to commodity prices by renegotiating a number of our commodity-based contracts, where revenues were subject to fluctuating commodity prices, to fee-based contracts.

Barnett Shale. In February 2003, we formed a joint venture, in which we own a 50% interest, to construct a gathering system in an area of the Barnett Shale gas formation, near Denton, Texas, at an initial cost of $3.0 million. The system consists of approximately 14 miles of gathering pipelines and the system is expected to have a capacity of approximately 35,000 Mcf/d.

Hallmark Lateral. In June 2002, we acquired from Florida Gas Transmission approximately 70 miles of 20 inch transmission line, which we refer to as the Hallmark Lateral. We constructed an

addition to this transmission line to connect our Gulf Coast and Corpus Christi systems. This connection lets us transport gas between our two systems, which reduces our dependence on third-party suppliers and allows us to move gas supplies to more favorable markets and enhance our margins. In November 2002, we completed construction of the interconnect between the Hallmark Lateral and the Florida Gas Transmission mainline. With this connection, we began selling gas into the Florida markets and we sold approximately 46,020 MMBtu/d into Florida for the six months ended June 30, 2003.

Other Developments

Distribution Increase. On July 10, 2003, we announced that the board of directors of our general partner has authorized for the quarter ended September 30, 2003 an increase in our quarterly distribution to $0.70 per unit, or $2.80 per unit on an annualized basis, from $0.55 per unit. This distribution will be payable on or about November 14, 2003. The board of directors of our general partner declared a quarterly distribution of $0.55 for the quarter ended June 30, 2003. This distribution was paid on August 15, 2003 to holders of record on July 31, 2003.

Bank Credit Facility. In June 2003, our operating partnership, Crosstex Energy Services, L.P., entered into a new $100.0 million senior secured credit facility, which matures in June 2006, consisting of a $70.0 million acquisition facility and a $30.0 million working capital and letter of credit facility. After giving effect to this offering, we expect our operating partnership to have approximately $63.2 million of the acquisition facility available for future borrowings.

Secured Notes Offering. In June 2003, our operating partnership entered into a master shelf agreement with an institutional lender pursuant to which it issued $30.0 million of senior secured notes with an interest rate of 6.95% and a maturity of seven years. In July 2003, our operating partnership issued $10.0 million of senior secured notes pursuant to the master shelf agreement with an interest rate of 6.88% and a maturity of seven years. The senior secured notes are guaranteed by our operating partnership's subsidiaries and us. Our operating partnership used the net proceeds from the senior notes offering to repay indebtedness under its bank credit facility.

Summary of Risk Factors

An investment in our common units involves risks associated with our business, our partnership structure and the tax characteristics of common units. Those risks are described under the caption "Risk Factors" beginning on page 16 and include:

Risks Inherent in Our Business

- We may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to enable us to pay the minimum quarterly distribution each quarter.
- We must continually compete for natural gas supplies, and any decrease in our supplies of natural gas could reduce our ability to make distributions to our unitholders.
- A substantial portion of our assets is connected to natural gas reserves that will decline over time, and the cash flows associated with those assets will accordingly decline.
- Our profitability is dependent upon prices and market demand for natural gas and NGLs, which are beyond our control and have been volatile.
- If we are unable to integrate our recent acquisitions, or if we do not continue to make acquisitions on economically acceptable terms, our future financial performance may be limited.
- We have limited control over the development of certain assets because we are not the operator.

- We expect to encounter significant competition in any new geographic areas into which we seek to expand and our ability to enter such markets may be limited.
- We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could reduce our ability to make distributions to our unitholders.
- We may not be able to retain existing customers or acquire new customers, which would reduce our revenues and limit our future profitability.
- We depend on certain key customers, and the loss of any of our key customers could adversely affect our financial results.
- We have a limited combined operating history.
- Our use of derivative financial instruments has in the past, and could in the future, result in financial losses or reduce our income.
- Due to our lack of asset diversification, adverse developments in our gathering, transmission, treating, processing and producer services businesses would reduce our ability to make distributions to our unitholders.
- Our success depends on key members of our management, the loss of whom could disrupt our business operations.

Risks Inherent in an Investment in Us

- Crosstex Energy Holdings Inc. controls our general partner and will own a 56% limited partner interest in us upon completion of the offering. Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor its own interests to the detriment of our unitholders.
- Our unitholders will have no right to elect our general partner or the directors of its general partner and will have limited ability to remove our general partner.
- Cost reimbursements due our general partner may be substantial and will reduce the cash available for distribution to you.
- The control of our general partner may be transferred to a third party, and that third party could replace our current management team, in each case without unitholder consent.
- Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.
- Our partnership agreement contains provisions which reduce the remedies available to unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.
- Our common units have a limited trading history and a limited trading volume compared to other stocks and units representing limited partner interests.

Tax Risks to Our Unitholders

- The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to our unitholders.
- A successful IRS contest of the federal income tax positions we take may adversely affect the market for common units, and the costs of any contest will be borne by us and, therefore, indirectly by our unitholders and our general partner.

- You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.
- Tax gain or loss on disposition of our common units could be different than expected.
- We are registered as a tax shelter. This may increase the risk of an IRS audit of us or a unitholder.

Competitive Strengths

We believe that we are well positioned to compete in the natural gas gathering, transmission, treating, processing and producer services businesses. Our competitive strengths include:

- *Strategic position in the Texas Gulf Coast and Mississippi*. Our Gregory and Conroe processing plants and approximately 59% of our total gathering and transmission pipeline miles are located in the Texas Gulf Coast. The Texas Gulf Coast is characterized by consistently high levels of drilling activity, which provide us with significant opportunities to access newly developed gas supplies. We believe our significant presence and asset base in the Texas Gulf Coast generally provides us with a competitive advantage in capturing new supplies of natural gas and markets for natural gas because of our resulting lower costs of handling newly connected gas and delivering it to market. The acquisition of the AIM pipeline system, located in south-central Mississippi, allowed us to establish a new core area outside of our strategic position in the Texas Gulf Coast.
- *Asset base with available capacity*. By aggressively marketing directly to producers and end users and adding connections to new customers, we believe we have the opportunity to leverage our existing asset base in order to more fully utilize the capacity of our systems and thereby significantly increase throughput and cash flows. Since our pipeline and gathering systems, including those acquired from DEFS, operated at an overall utilization of approximately 47% of capacity in the first six months of 2003, transporting additional volumes of natural gas through our systems should provide incremental operating income. We believe our inventory of 13 treating plants gives us a competitive advantage for capturing new treating business since we can often have a plant in service faster than our competitors.
- *Range of services*. We offer a full range of midstream services to natural gas producers, including gathering, transmission, treating, processing and marketing. In addition, as a component of our producer services business, we purchase natural gas for sale to others, and, in doing so, provide risk management opportunities to natural gas producers. We believe this full range of services gives us advantages in competing for new business because we can provide substantially all the services a producer requires to get its production of natural gas to market, as compared to our competitors who often do not provide a full range of services. In addition, we provide a full range of services to natural gas buyers, including an aggregated supply of natural gas, load balancing and price risk management, which allows buyers to find a significant volume of natural gas that meets their requirements without having to negotiate with multiple producers.
- *Proven acquisition and development expertise*. Since January 2000, we have acquired and integrated 13 operations with an aggregate purchase price of approximately $142.3 million, including our recent $67.3 million acquisition of assets from DEFS which enabled us to expand our operations into Mississippi and Alabama. Our management team's significant industry contacts have enabled us to become aware of, and gain access to, strategic acquisition opportunities. We intend to use our experience and reputation in strategically acquiring assets to continue to grow through accretive acquisitions, focusing on opportunities in which we see potential to improve throughput volumes and cash flows through marketing and new construction and expansion projects. We have invested in excess of $50.0 million in our construction and expansion projects from January 2000 through June 2003.

- *Flexible financial structure*. Our operating partnership has a $70.0 million acquisition facility, approximately $63.2 million of which will be available upon the closing of this offering, and a $30.0 million working capital and letter of credit facility. In addition, our operating partnership has a $50.0 million master shelf facility for senior secured notes. Our operating partnership has issued $40.0 million of senior secured notes under this facility, and any future issuances will be subject to negotiation of certain terms, including pricing. We believe the available capacity under the bank credit facility and the senior secured notes, combined with our ability to access the capital markets, should provide us with a flexible financial structure that will facilitate our expansion and acquisition strategy.
- *Experienced and motivated management.* Our management team's extensive experience and contacts within the midstream industry provides a strong foundation for managing and enhancing our operations, for accessing strategic acquisition opportunities and for constructing new assets. Our senior management team, which indirectly owns approximately 49,000 common units, approximately 686,000 subordinated units and approximately 15% of our general partner, has an average of over 20 years of industry experience primarily with the type of assets and the markets in which we currently operate. Please read "Management—Directors and Executive Officers of Crosstex Energy GP, LLC" beginning on page 86 for a discussion of the experience of our executive officers.

Business Strategy

Our strategy is to increase distributable cash flow per unit by making accretive acquisitions of assets that are essential to the production, transportation and marketing of natural gas, improving the profitability of our assets by increasing their utilization while controlling costs and pursuing new construction or expansion opportunities in our core operating areas. Key elements of our strategy include the following:

- *Pursuing accretive acquisitions*. We intend to use our substantial 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 assets. We pursue acquisitions that we believe will add to our core areas in order to capitalize on our existing infrastructure, personnel and producer and consumer relationships. We also examine opportunities to establish new core areas in regions with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas.
- *Improving existing system profitability.* After we acquire or construct a new system, we begin an aggressive effort to market directly to both producers and end users in order to connect new supplies of natural gas, increase volumes and more fully utilize the system's capacity. Many of our recently acquired systems have excess capacity that provides us opportunities to increase throughput with minimal incremental cost.
- *Undertaking construction and expansion opportunities*. We leverage our existing infrastructure and producer and customer relationships by constructing and expanding systems to meet new or increased demand for our gathering, transmission, treating, processing and marketing services. These projects include expansion of existing systems and construction of new facilities.

Partnership Structure And Management

Our operations are conducted through, and our operating assets are owned by, our operating partnership, Crosstex Energy Services, L.P., and its subsidiaries. Upon completion of this offering:

- the public unitholders will own a 42.3% limited partner interest in us, represented by 3,800,000 common units;

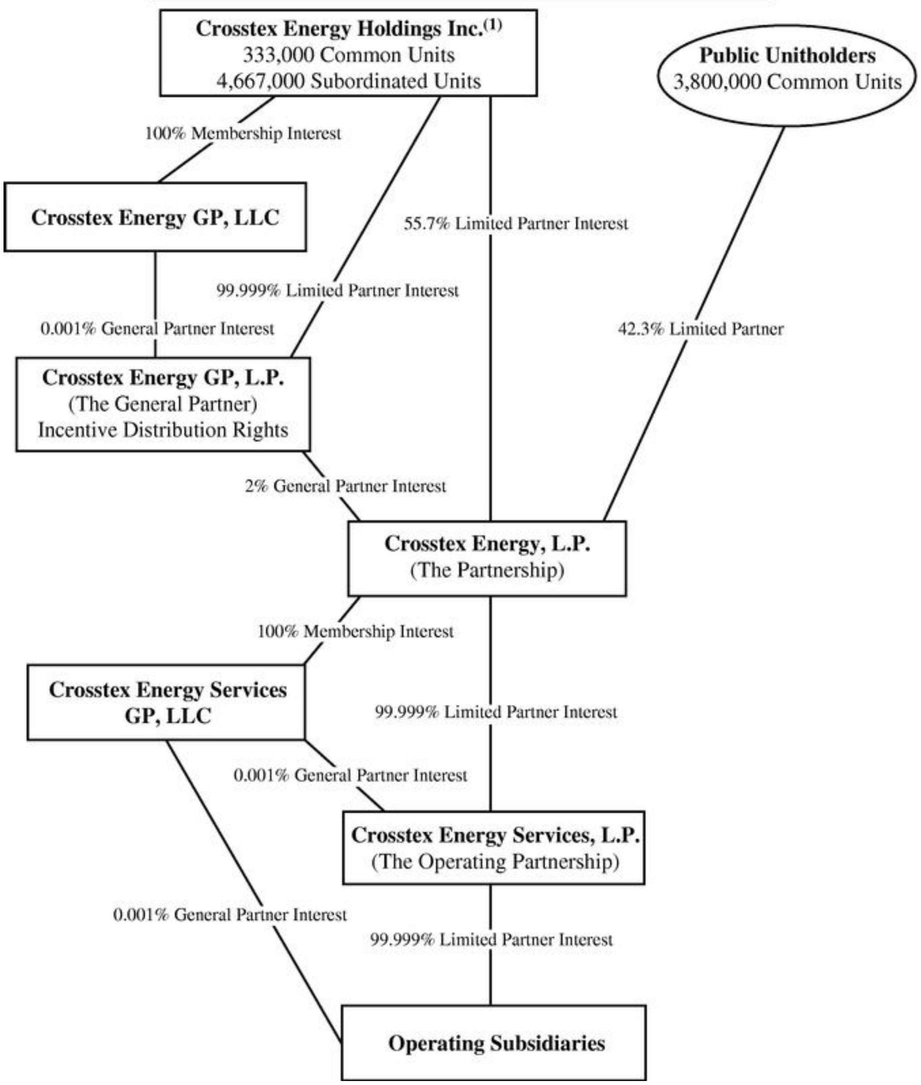
- Crosstex Energy Holdings Inc. will own a 55.7% limited partner interest in us, represented by 333,000 common units and 4,667,000 subordinated units; and
- our general partner will continue to own a 2% general partner interest in us and all of our incentive distribution rights.

Our principal executive offices are located at 2501 Cedar Springs, Suite 600, Dallas, Texas 75201, and our phone number is (214) 953-9500.

The chart on the following page depicts the organization and ownership of us and our operating partnership after giving effect to the offering.

Ownership of Crosstex Energy, L.P.

Common Units:	
Public Unitholders	42.3%
Crosstex Energy Holdings Inc.	3.7%
Subordinated Units:	
Crosstex Energy Holdings Inc.	52.0%
General Partner Interest	2.0%
	100.0%



(1) For ownership of Crosstex Energy Holdings Inc., please see "Security Ownership of Certain Beneficial Owners and Management" beginning on page 94.

THE OFFERING

Common units offered by Crosstex Energy, L.P.	1,500,000 common units.
	1,725,000 common units if the underwriters exercise their over-allotment option in full.
Units outstanding after this offering	4,133,000 common units, representing a 46.0% limited partner interest in Crosstex Energy, L.P., and 4,667,000 subordinated units, representing a 52.0% limited partner interest in Crosstex Energy, L.P. Approximately 8.1% of the common units and all of the subordinated units will be owned by affiliates of our general partner.
Use of proceeds	We intend to use all of the net proceeds of this offering to repay a portion of the borrowings under the bank credit facility incurred in connection with recent acquisitions and capital projects, including the DEFS acquisition. Please read "Use of Proceeds" on page 32.
Cash distributions	Common units are entitled to receive distributions of available cash of $0.50 per quarter, or $2.00 on an annualized basis, before any distributions are paid on our subordinated units.
	In general, we will pay any cash distributions we make each quarter in the following manner:
	• first, 98% to the common units and 2% to the general partner, until each common unit has received a minimum quarterly distribution of $0.50 plus any arrearages from prior quarters; and
	• second, 98% to the subordinated units and 2% to the general partner, until each subordinated unit has received a minimum quarterly distribution of $0.50.
	If cash distributions exceed $0.50 per unit in a quarter, our general partner will receive increasing percentages, up to 50%, of the cash we distribute in excess of that amount. We refer to these distributions as "incentive distributions." Please read "Cash Distribution Policy—Incentive Distribution Rights" on page 39.
	We must distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner in its sole discretion. These reserve funds are meant to provide for the proper conduct of our business including funds needed to provide for our operations as well as to comply with applicable debt instruments. As we cannot estimate the size of these reserves for any given quarter at this time, we cannot assure you that, after the establishment of reserves, we will have cash on hand for distribution to our unitholders. We refer to this cash available for distribution as "available cash," and we define its meaning in our partnership agreement. Please read "Cash Distribution Policy—Distributions of Available Cash" beginning on page 35 for a description of available cash. The amount of available cash may be greater than or less than the minimum quarterly distribution.

Timing of distributions	We pay distributions approximately 45 days after March 31, June 30, September 30 and December 31 to the unitholders of record on the applicable record date.
Subordination period	The subordination period will end once we meet the financial tests in the partnership agreement, but it generally cannot end before December 31, 2007.
	When the subordination period ends, each remaining subordinated unit will convert into one common unit and the common units will no longer be entitled to arrearages. Please read "Cash Distribution Policy—Subordination Period" beginning on page 37.
Early conversion of subordinated units	If we meet the applicable financial tests in the partnership agreement for any three consecutive four-quarter periods ending on or after December 31, 2005, 25% of the subordinated units will convert into common units. If we meet these tests for any three consecutive four-quarter periods ending on or after December 31, 2006, an additional 25% of the subordinated units will convert into common units. The early conversion of the second 25% of the subordinated units may not occur until at least one year after the early conversion of the first 25% of the subordinated units.
Issuance of additional units	In general, while any subordinated units remain outstanding, we may not issue more than 1,316,500 additional common units without obtaining unitholder approval. We may, however, issue an unlimited number of common units for acquisitions, capital improvements or debt repayments that increase cash flow from operations per unit on a pro forma basis.

Voting rights	Our general partner manages and operates us. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner or the directors of its general partner on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/3$% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. Because affiliates of our general partner will own 56.8% of the outstanding units upon completion of the offering, you will not be able to remove the general partner without its consent.
Limited call right	If at any time more than 80% of the outstanding common units are owned by our general partner and its affiliates, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then-current market price of the common units.

Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through December 31, 2006, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be 20% or less of the cash distributed to you with respect to that period. Please read "Material Tax Consequences—Tax Consequences of Unit Ownership—Ratio of taxable income to distributions" on page 123 for the basis of this estimate.
Exchange listing	Our common units are traded on the Nasdaq National Market under the symbol "XTEX."

SUMMARY HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table sets forth summary historical financial and operating data for Crosstex Energy, L.P. and our predecessor, Crosstex Energy Services, Ltd., as of and for the dates and periods indicated and summary pro forma financial and operating data for us as of and for the year ended December 31, 2002 and the six months ended June 30, 2003. The summary historical financial data for the four months ended April 30, 2000, the eight months ended December 31, 2000, and the years ended December 31, 2001 and 2002, are derived from the audited financial statements of Crosstex Energy, L.P. and its predecessor. The summary historical financial data for the six months ended June 30, 2002 and 2003 are derived from our unaudited financial statements and, in our opinion, have been prepared on the same basis as the audited financial statements and include all adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of this information. As described in our historical financial statements, the investment in our predecessor by Yorktown Energy Partners IV, L.P. in May 2000 resulted in the dissolution of the predecessor partnership and the creation of a new partnership with the same organization, purpose, assets and liabilities. Accordingly, the audited financial statements for 2000 are divided into the four months ended April 30, 2000 and the eight months ended December 31, 2000 because a new basis of accounting was established effective May 1, 2000 to give effect to the Yorktown transaction. In addition, the summary historical financial and operating data include the results of operations of the Arkoma system beginning in September 2000, the Gulf Coast system beginning in September 2000 and the CCNG system, which includes the Corpus Christi system, the Gregory gathering system and the Gregory processing plant, beginning in May 2001.

The summary pro forma financial and operating data reflect our consolidated historical operating results as adjusted for the DEFS acquisition, the senior secured note offerings, this offering and, in the case of the pro forma statement of operations for the year ended December 31, 2002, our initial public offering. The summary pro forma financial data is derived from the unaudited pro forma financial statements. The pro forma balance sheet assumes that the issuance of $10.0 million of senior secured notes and this offering occurred on June 30, 2003. The pro forma statements of operations assume that the DEFS acquisition, the senior secured note offerings, this offering and our initial public offering occurred on January 1, 2002. For a description of all of the assumptions used in preparing the summary pro forma financial data, you should read the notes to the pro forma financial statements. The pro forma financial and operating data should not be considered as indicative of the historical results we would have had or the future results that we will have after the offering.

We derived the information in the following table from, and that information should be read together with, and is qualified in its entirety by reference to, the historical and pro forma financial statements and the accompanying notes included in this prospectus. The table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 47.

	Crosstex Energy, L.P.(1)							
	Predecessor	Historical					Pro Forma as Adjusted	
					Unaudited		Unaudited	
	Four Months Ended April 30,	Eight Months Ended December 31,	Year Ended December 31,		Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	2000	2000	2001	2002	2002	2003	2002	2003
	(in thousands, except per unit amounts)							
Statement of Operations Data:								
Revenues:								
Midstream	$ 3,591	$ 88,008	$ 362,673	$ 437,676	$ 200,595	$ 469,345	$ 574,757	$ 575,667
Treating	5,947	17,392	24,353	14,817	6,878	10,477	14,817	10,477

Total revenues	9,538	105,400	387,026	452,493	207,473	479,822	589,574	586,144
Operating costs and expenses:								
Midstream purchased gas	2,746	83,672	344,755	413,982	189,675	451,479	534,839	549,317
Treating purchased gas	4,731	14,876	18,078	5,767	2,599	4,451	5,767	4,451
Operating expenses	544	1,796	7,430	10,468	5,050	6,545	15,661	9,643
General and administrative(2)	810	2,010	5,914	8,454	4,206	3,391	6,000	3,391
Stock based compensation	8,802	—	—	41	—	3,072	41	3,072
Impairments	—	—	2,873	4,175	3,150	—	4,175	—
(Profit) loss on energy trading	(638)	(1,253)	3,714	(2,703)	(2,754)	(845)	(2,703)	(845)
Depreciation and amortization	522	2,261	6,101	7,745	3,884	5,046	12,180	7,339
Total operating costs and expenses	17,517	103,362	388,865	447,929	205,810	473,139	575,960	576,368
Operating income (loss)	(7,979)	2,038	(1,839)	4,564	1,663	6,683	13,614	9,776
Other income (expense):								
Interest expense, net	(79)	(530)	(2,253)	(2,717)	(1,696)	(875)	(3,281)	(1,828)
Other income (expense)	381	115	174	155	5	(1)	155	(1)
Total other income (expense)	302	(415)	(2,079)	(2,562)	(1,691)	(876)	(3,126)	(1,829)
Net income (loss)	$ (7,677)	$ 1,623	$ (3,918)	$ 2,002	$ (28)	$ 5,807	$ 10,488	$ 7,947
Net income per limited partner unit(3)	N/A	N/A	N/A	$ 0.04	N/A	$ 0.77	$ 1.17	$ 0.88
Balance Sheet Data (at period end):								
Working capital surplus (deficit)	$ (4,005)	$ 5,861	$ (2,254)	$ (8,672)	$ (8,672)	$ (11,019)		$ (11,019)
Property and equipment, net	10,540	37,242	84,951	109,948	109,948	188,986		188,986
Total assets	45,051	201,268	168,376	232,438	232,438	352,565		352,565
Total debt	7,000	22,000	60,000	22,550	22,500	98,750		47,527
Partners' equity	3,608	40,354	41,155	89,816	89,816	92,781		144,004
Cash Flow Data:								
Net cash flow provided by (used in):								
Operating activities	$ 7,380	$ 7,741	$ (8,326)	$ 19,956	$ 27,084	$ 15,141		
Investing activities	(2,849)	(25,643)	(52,535)	(33,240)	(10,337)	(85,238)		
Financing activities	198	36,557	42,558	14,240	(2,700)	70,415		
Other Financial Data:								
Midstream gross margin	$ 845	$ 4,336	$ 17,918	$ 23,694	$ 10,920	$ 17,866	$ 39,918	$ 26,350
Treating gross margin	1,216	2,516	6,275	9,050	4,279	6,026	9,050	6,026
Total gross margin(4)	2,061	6,852	24,193	32,744	15,199	23,892	48,968	32,376
EBITDA(5)	(7,076)	4,414	4,436	12,464	5,552	11,728	25,949	17,114
Maintenance capital expenditures		57	1,922	2,350	592	1,719		
Expansion capital expenditures		25,743	50,766	30,980	9,813	82,873		
Total capital expenditures(6)		$ 25,800	$ 52,688	$ 33,330	$ 10,405	$ 84,592		
Operating Data (MMBtu/d):								
Pipeline throughput	23,098	104,185	313,103	392,681	386,110	504,477	501,233	603,160
Natural gas processed	30,699	15,661	60,629	85,776	89,279	93,654	118,239	123,438
Treating volumes(7)	26,872	35,910	62,782	97,866	95,895	88,994	97,866	88,994

(1) Crosstex Energy, L.P. is the successor to Crosstex Energy Services, Ltd. Results of operations and balance sheet data prior to May 1, 2000 represent historical results of the predecessor to Crosstex Energy Services, Ltd. These results are not necessarily comparable to the results subsequent to May 2000 due to the new basis of accounting.

(2) For the twelve month period ending in December 2003, the amount for which our general partner is entitled to reimbursement from us for allocated general and administrative expenses is limited to $6.0 million. Such limitation does not apply to expenses incurred in connection with acquisition or business development opportunities evaluated on our behalf.

(3) Net income (loss) per limited partner unit is not applicable for periods prior to our initial public offering. Net income per unit of $0.04 for the year ended December 31, 2002 represents allocation of our 2002 net income for the period from December 17, 2002 to December 31, 2002.

(4) Gross margin is defined as revenue less related cost of purchased gas.

(5) We define EBITDA as net income (loss) plus interest expense, provision for income taxes and depreciation and amortization expense. EBITDA is used as a supplemental financial measure by management and by external users of our financial

statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (a) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis; (b) our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing and capital structure; and (c) the viability of projects and the overall rates of return on alternative investment opportunities. EBITDA should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA is not intended to represent cash flow. Because EBITDA excludes some, but not all, items that affect net income and these measures may vary among other companies, the EBITDA data presented may not be comparable to similarly titled measures of other companies.

The following table reconciles EBITDA to net income (loss):

	Crosstex Energy, L.P.							
	Predecessor	Historical					Pro Forma as Adjusted	
					Unaudited		Unaudited	
	Four Months Ended April 30,	Eight Months Ended December 31,	Year Ended December 31,		Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	2000	2000	2001	2002	2002	2003	2002	2003
			(in thousands)					
EBITDA Reconciliation:								
Net income (loss)	$ (7,677)	$ 1,623	$ (3,918)	$ 2,002	$ (28)	$ 5,807	$ 10,488	$ 7,947
Plus:								
Depreciation and amortization	522	2,261	6,101	7,745	3,884	5,046	12,180	7,339
Interest expense, net	79	530	2,253	2,717	1,696	875	3,281	1,828
EBITDA	$ (7,076)	$ 4,414	$ 4,436	$ 12,464	$ 5,552	$ 11,728	$ 25,949	$ 17,114

Our predecessors were partnerships and had no income tax expense. EBITDA for the years ended December 31, 2001 and 2002 and the six months ended June 30, 2002 has been reduced by non-cash impairment charges of $2.9 million, $4.2 million and $3.2 million, respectively, and the six months ended June 30, 2003 has been reduced by non-cash stock-based compensation charges of $3.1 million.

(6) Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives. Expansion capital expenditures are capital expenditures made to expand the existing operating capacity of our assets, whether through construction or acquisition. We treat repair and maintenance expenditures that do not extend the useful life of existing assets as operating expenses as we incur them.

(7) Represents volumes for treating plants operated by us whereby we receive a fee based on the volumes treated.

SUMMARY OF CONFLICTS OF INTEREST AND FIDUCIARY RESPONSIBILITIES

Crosstex Energy GP, L.P., our general partner, has a legal duty to manage us in a manner beneficial to our unitholders. This legal duty originates in statutes and judicial decisions and is commonly referred to as a "fiduciary" duty. However, because Crosstex Energy GP, L.P. is indirectly owned by Crosstex Energy Holdings Inc., the officers and directors of Crosstex Energy GP, LLC, who manage and operate our general partner, have fiduciary duties to manage the business of our general partner in a manner beneficial to Crosstex Energy Holdings Inc. The officers and directors of Crosstex Energy GP, LLC have significant relationships with, and responsibilities to, Crosstex Energy Holdings Inc. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its affiliates, on the other hand. For a more detailed description of the conflicts of interest and fiduciary responsibilities of our general partner, please read "Conflicts of Interest and Fiduciary Responsibilities" beginning on page 98.

Our general partner is permitted to resolve conflicts of interest by considering the interests of all the parties involved. Therefore, our general partner can consider the interests of its affiliates if a conflict of interest arises between the common unitholders and our general partner and its affiliates. Crosstex Energy GP, LLC has a conflicts committee, consisting of three independent members of its board of directors, that is available to review matters involving conflicts of interest. C. Roland Haden, Stephen A. Wells and Robert F. Murchison, all of whom are directors of Crosstex Energy GP, LLC, are members of the conflicts committee. Please read "Management—Directors and Executive Officers of Crosstex Energy GP, LLC" beginning on page 86 for a discussion of the directors of Crosstex Energy GP, LLC.

Our partnership agreement limits the liability and reduces the fiduciary duties owed by our general partner to the unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions that might otherwise constitute breaches of our general partner's fiduciary duty. By purchasing a common unit, you are treated as having consented to various actions contemplated in the partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary or other duties under applicable state law.

We have entered into an agreement with Crosstex Energy Holdings Inc. whereby it has agreed not to engage in the business of gathering, transmitting, treating, processing and marketing of natural gas. In addition, our general partner does not receive any management fee or other compensation for its management of us, but our general partner and its affiliates are reimbursed for general and administrative expenses incurred on our behalf. For the twelve month period ending in December 2003, the amount which we will reimburse the general partner and its affiliates for costs incurred with respect to the general and administrative services performed on our behalf will not exceed $6.0 million. For a more detailed discussion of these agreements, please read "Certain Relationships and Related Transactions" beginning on page 96.

RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the following risk factors, which we believe include the risks material to our business, together with all of the other information included in this prospectus in evaluating an investment in the common units.

If any of the following risks were actually to occur, our business, financial condition, or results of operations could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Inherent in Our Business

We may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to enable us to pay the minimum quarterly distribution each quarter.

We may not have sufficient available cash each quarter to pay the minimum quarterly distribution. Under the terms of our partnership agreement, we must pay our general partner's fees and expenses and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things;

- the amount of natural gas transported in our gathering and transmission pipelines;
- the level of our processing and treating operations;
- the fees we charge and the margins we realize for our services;
- the price of natural gas;
- the relationship between natural gas and NGL prices; and
- our level of operating costs.

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

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

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

We must continually compete for natural gas supplies, and any decrease in our supplies of natural gas could reduce our ability to make distributions to our unitholders.

Competition is intense in many of our markets. The principal areas of competition include obtaining gas supplies and the marketing and transportation of natural gas and NGLs. Our competitors include major integrated oil companies, interstate and intrastate pipelines and natural gas gatherers and processors. Our competitors in the Texas Gulf Coast area include El Paso Field Services, Kinder Morgan Inc., Houston Pipeline Company and Duke Energy Field Services. Our competitors in Mississippi include Southern Natural Gas and Gulf South Pipeline Company. Some of our competitors offer more services or have greater financial resources and access to larger natural gas supplies than we do.

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

In order to maintain or increase throughput levels in our natural gas gathering systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies. We may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity near our gathering systems. Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in natural gas production or in the level of drilling activity in our principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position. See "Business—Natural Gas Supply" on page 79 for more information on our supplies of natural gas.

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

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

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

We are subject to significant risks due to fluctuations in commodity prices. These risks are based upon three components of our business: (1) the purchase of certain volumes of natural gas at a price that is a percentage of a relevant index; (2) certain processing contracts for our Gregory system whereby we are exposed to natural gas and NGL commodity price risks; and (3) part of our fee from the Seminole gas plant is based on a portion of the NGLs produced, and, therefore, is subject to commodity price risks.

The margins we realize from purchasing and selling a portion of the natural gas that we transport through our pipeline systems decrease in periods of low natural gas prices because our gross margins are based on a percentage of the index price. For the year ended December 31, 2002 and the six months ended June 30, 2003, we purchased approximately 6.1% and 8.1%, respectively, of our gas at a percentage of relevant index. Accordingly, a decline in the price of natural gas could have an adverse impact on our results of operations.

A portion of our profitability is affected by the relationship between natural gas and NGL prices. For a component of our Gregory system volumes, we purchase natural gas, process natural gas and extract NGLs, and then sell the processed natural gas and NGLs. Since we extract Btus from the gas stream in the form of the liquids or consume it as fuel during processing, we reduce the Btu content of the natural gas. Accordingly, our margins under these arrangements can be negatively affected in periods in which the value of natural gas is high relative to the value of NGLs. For example, a decrease of $0.01 per gallon in the price of NGLs and an increase of $0.10 per MMBtu in the average price of natural gas for the six months ended June 30, 2003 would have resulted in a decrease in processing margins of approximately $109,051. For the six months ended June 30, 2003, we purchased approximately 22% of the natural gas volumes on our Gregory system under such contracts.

In the past, the prices of natural gas and NGLs have been extremely volatile and we expect this volatility to continue. For example, in 2001, the NYMEX settlement price for natural gas for the prompt month contract ranged from a high of $9.98 per MMBtu to a low of $1.83 per MMBtu. In 2002, the same index ranged from $4.13 per MMBtu to $2.01 per MMBtu. For the six months ended June 30, 2003, the same index ranged from $9.13 per MMBtu to $4.99 per MMBtu. A composite of the OPIS Mt. Belvieu monthly average liquids price based upon our average liquids composition in 2001 ranged from a high of approximately $0.71 per gallon to a low of approximately $0.27 per gallon. In 2002, the same composite ranged from approximately $0.48 per gallon to approximately $0.27 per gallon. For the six months ended June 30, 2003, the same composite ranged from approximately $0.65 per gallon to approximately $0.46 per gallon.

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

The markets and prices for residue gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

If we are unable to integrate our recent acquisitions, or if we do not continue to make acquisitions on economically acceptable terms, our future financial performance may be limited.

We recently completed the DEFS acquisition, which geographically expanded our operations into Alabama and Mississippi. For the year ended December 31, 2002, the DEFS assets would have constituted 33.3% of our pro forma gross margin and 15.8% of our pro forma EBITDA. We cannot assure you that we will successfully integrate this or any other acquisition into our operations, or that we will achieve the desired profitability from such acquisitions. Failure to successfully integrate these

substantial acquisitions could adversely affect our operations and cash flows available for distribution to our unitholders.

Our future financial performance will depend, in part, on our ability to make acquisitions of assets and businesses at attractive prices. From time to time, we will evaluate and seek to acquire assets or businesses that we believe complement our existing business and related assets. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets;
- the diversion of management's attention from other business concerns;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental liabilities and title problems.

Management's assessment of these risks is necessarily inexact and may not reveal or resolve all existing or potential problems with an acquisition.

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

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

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

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

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

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

We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could reduce our ability to make distributions to our unitholders.

Risks of nonpayment and nonperformance by our customers are a major concern in our business. Several participants in the energy industry have been receiving heightened scrutiny from the financial markets in light of the collapse of Enron Corp. We are subject to risks of loss resulting from

nonpayment or nonperformance by our customers. We recognized a charge of $5.7 million in 2001 for sales contracts with Enron. These contracts related to our producer services operations in which we purchased and sold natural gas that did not move on our gathering and transmission systems. Any increase in the nonpayment and nonperformance by our customers could reduce our ability to make distributions to our unitholders.

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

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

For the six months ended June 30, 2003, approximately 56% of our sales of gas which were transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

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

We currently derive a significant portion of our revenues from contracts with a subsidiary of Kinder Morgan Inc. To the extent that Kinder Morgan Inc. and other customers may reduce volumes of natural gas purchased under existing contracts, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers. Sales to the subsidiary of Kinder Morgan Inc. accounted for 22.4% of our revenues during the first six months of 2003, 27.5% of our revenues during 2002 and 23.9% of our revenues during 2001. Our agreements with our key customers provide for minimum volumes of natural gas that each customer must purchase until the expiration of the term of the applicable agreement, subject to certain force majeure provisions. Our customers may default on their obligations to purchase the minimum volumes required under the applicable agreements. Our primary contract with Kinder Morgan Inc. expires in March 2006.

We have a limited combined operating history.

Because we have grown rapidly, we have a limited operating history for most of our operations to which you may look to evaluate our performance. As a result, the historical and pro forma information may not give you an accurate indication of what our actual results would have been if the acquisitions had been completed at the beginning of the periods presented or of what our future results of operations are likely to be.

Growing our business by constructing new pipelines and processing and treating facilities subjects us to construction risks and risks that natural gas supplies will not be available upon completion of the facilities.

One of the ways we intend to grow our business is through the construction of additions to our existing gathering systems and construction of new gathering, processing and treating facilities. We are nearing completion of construction activities to expand our Gregory processing plant at an estimated cost of $8.0 million. The construction of gathering, processing and treating facilities requires the

expenditure of significant amounts of capital, which may exceed our expectations. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

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

Our operations are subject to the many hazards inherent in the gathering, compressing, treating and processing of natural gas and storage of residue gas, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs and other hydrocarbons; and
- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. Our operations are concentrated in the Texas Gulf Coast, and a natural disaster or other hazard affecting this region could have a material adverse effect on our operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems which would cover damage to the pipelines. We are not insured against all environmental accidents which might occur, other than those considered to be sudden and accidental. Our business interruption insurance covers only our Gregory processing plant. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

Terrorist attacks, such as the attacks that occurred on September 11, 2001, have resulted in increased costs, and future war or risk of war may adversely impact our results of operations and our ability to raise capital.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scope. These attacks caused instability in the global financial markets and other industries, including the energy industry. Uncertainty surrounding retaliatory military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, and the possibility that infrastructure facilities, including pipelines, production facilities, and transmission and distribution facilities, could be direct targets, or indirect casualties, of an act of terror. Instability in the financial markets as a result of terrorism, the war in Iraq or future developments could also affect our ability to raise capital.

The terrorist attacks on September 11, 2001 and the changes in the insurance markets attributable to the September 11 attacks have made certain types of insurance more difficult for us to obtain. Our insurance policies now generally exclude acts of terrorism as compared to our policies prior to September 11, 2001. Such insurance is not available at what we believe to be acceptable pricing levels. A lower level of economic activity could also result in a decline in energy consumption, which could adversely affect our revenues or restrict our future growth. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Our indebtedness may limit our ability to borrow additional funds, make distributions to you or capitalize on acquisitions or other business opportunities.

Upon completion of this offering, we expect our total outstanding long-term indebtedness to be approximately $47.5 million, including $40.0 million of senior secured notes, $6.8 million under the bank credit facility and approximately $0.7 million of other indebtedness. Payments of principal and interest on the indebtedness will reduce the cash available for distribution on the units. The bank credit facility and senior secured notes contain various covenants limiting our ability to incur indebtedness, grant liens, engage in transactions with affiliates, make distributions to our unitholders and capitalize on acquisition or other business opportunities. The bank credit facility and our senior secured notes also contain covenants requiring us to maintain certain financial ratios, such as debt to EBITDA, EBITDA to interest, current assets to current liabilities and minimum tangible net worth. We are prohibited from making any distribution to unitholders if such distribution would cause a default or an event of default under the bank credit facility or the senior secured notes. Each of the bank credit facility and the senior secured notes limits the use of borrowings under the bank credit facility to pay distributions to unitholders to $5.0 million over the term of the bank credit facility. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Description of Indebtedness" beginning on page 62 for a discussion of the bank credit facility and senior secured notes.

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

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

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

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

The states in which we conduct operations administer federal pipeline safety standards under the Pipeline Safety Act of 1968. The "rural gathering exemption" under the Natural Gas Pipeline Safety Act of 1968 presently exempts substantial portions of our gathering facilities from jurisdiction under that statute, including those portions located outside of cities, towns, or any area designated as residential or commercial, such as a subdivision or shopping center. The "rural gathering exemption," however, may be restricted in the future, and it does not apply to our natural gas transmission pipelines. In response to recent pipeline accidents in other parts of the country, Congress and the Department of Transportation have passed or are considering heightened pipeline safety requirements. See "Business—Regulation" beginning on page 79.

Compliance with pipeline integrity regulations issued by the TRRC, or those soon to be issued by the United States Department of Transportation, or DOT, could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. In addition, the DOT is expected to issue regulations for interstate pipeline testing in late 2003. We expect our costs relating to compliance with the required testing under the TRRC regulations to be approximately $1.0 million in 2003 and between $1.0 million and $2.0 million in each of 2004 and 2005. If our pipelines fail to meet the safety standards mandated by the TRRC regulations, then we may be required to repair or replace sections of such pipelines, the cost of which cannot be estimated at this time.

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

Many of the operations and activities of our gathering systems, plants and other facilities are subject to significant federal, state and local environmental laws and regulations. These include, for example, laws and regulations that impose obligations related to air emissions and discharge of wastes from our facilities and the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal. Various governmental authorities have the power to enforce compliance with these regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Liability may be incurred without regard to fault for the remediation of contaminated areas. Private parties, including the owners of properties through which our gathering systems pass, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability. See "Business—Environmental Matters" beginning on page 81.

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

We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions, and we use futures and option contracts traded on the New York Mercantile Exchange. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. We currently have hedges in place on 130,000 MMBtu of gas per month at prices ranging from $3.29 per MMBtu to $5.56 per MMBtu for the period from July 1, 2003 to September 30, 2003,

100,000 MMBtu of gas per month at prices ranging from $4.02 per MMBtu to $6.13 per MMBtu for the period from October 1, 2003 to December 31, 2003, 90,000 MMBtu of gas per month at prices ranging from $4.02 per MMBtu to $5.67 per MMBtu for the period from January 1, 2004 to March 31, 2004, 70,000 MMBtu of gas per month at prices ranging from $4.67 per MMBtu to $5.49 per MMBtu for the period from April 1, 2004 to June 30, 2004, and 30,000 MMBtu of gas per month at a price of $4.85 per MMBtu for the period from July 1, 2004 to December 31, 2004. We estimate that these quantities represent approximately 100%, 80%, 75%, 60% and 28% of the margin on natural gas that we will buy at a percentage of index and upon which we will be exposed to the risk of fluctuations in natural gas prices. We could incur financial losses or fail to recognize the full value of a market opportunity as a result of volatility in the market values of the underlying commodities or if one of our counterparties fails to perform under a contract. For additional information about our risk management activities, including our use of derivative financial instruments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosures About Market Risk" on pages 65 and 66.

Due to our lack of asset diversification, adverse developments in our gathering, transmission, treating, processing and producer services businesses would reduce our ability to make distributions to our unitholders.

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

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

We depend on the continued employment and performance of the officers of the general partner of our general partner and key operational personnel. The general partner of our general partner has entered into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any "key man" life insurance for any officers. See "Management" beginning on page 85.

Risks Inherent in an Investment in Us

Crosstex Energy Holdings Inc. controls our general partner and will own a 56% limited partner interest in us upon completion of this offering. Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor its own interests to the detriment of our unitholders.

Following this offering, Crosstex Energy Holdings Inc. will indirectly own an aggregate limited partner interest of approximately 56% in us. In addition, Crosstex Energy Holdings Inc. owns and controls our general partner. Due to its control of our general partner and the size of its limited partner interest in us, Crosstex Energy Holdings Inc. effectively controls all limited partnership decisions, including any decisions related to the removal of our general partner. Conflicts of interest may arise in the future between Crosstex Energy Holdings Inc. and its affiliates, including our general partner, on the one hand, and our partnership or any of the unitholders, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates over the interests of the unitholders. These conflicts include, among others, the following situations:

Conflicts Relating to Control:

- our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to unitholders for actions that might, without these

limitations, constitute breaches of fiduciary duty by our general partner. As a result of purchasing units, our unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law;

- in resolving conflicts of interest, our general partner is allowed to take into account the interests of parties in addition to our unitholders, which has the effect of limiting its fiduciary duties to the unitholders;
- our general partner's affiliates may engage in limited competition with us;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- in some instances our general partner may cause us to borrow funds from affiliates of the general partner or from third parties in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units or to make incentive distributions or hasten the expiration of the subordination period; and
- our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution. Our general partner may establish reserves for distribution on the subordinated units, but only if those reserves will not prevent us from distributing the full minimum quarterly distribution, plus any arrearages, on the common units for the following four quarters.

Conflicts Relating to Costs:

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner interests and reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us; and
- our general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf, except for certain limitations on general and administrative expenses which expire in December 2003.

Please read "Conflicts of Interest and Fiduciary Responsibilities" beginning on page 98 and "Certain Relationships and Related Transactions—Relationship with Crosstex Energy Holdings Inc.—Omnibus Agreement" on page 96.

Our unitholders have no right to elect our general partner or the directors of its general partner and have limited ability to remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of its general partner and have no right to elect our general partner or the board of directors of its general partner on an annual or other continuing basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The general partner generally may not be removed except upon the vote of the holders of $66^{2}/_{3}$% of the outstanding units voting together as a single class.

Because affiliates of the general partner will control approximately 56.8% of all the units upon completion of this offering, the general partner currently cannot be removed without the consent of the general partner and its affiliates. Also, if the general partner is removed without cause during the subordination period and units held by the general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. A removal without cause would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units which would otherwise have continued until we had met certain distribution and performance tests.

Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud, gross negligence, or willful or wanton misconduct in its capacity as our general partner. Cause does not include, in most cases, charges of poor management of the business, so the removal of the general partner because of the unitholders' dissatisfaction with the general partner's performance in managing our partnership will most likely result in the termination of the subordination period.

In addition, unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner's general partner, cannot be voted on any matter. In addition, the partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, it will be more difficult for a third party to acquire our partnership without first negotiating such a purchase with our general partner and, as a result, you are less likely to receive a takeover premium.

Cost reimbursements due our general partner may be substantial and will reduce the cash available for distribution to you.

Prior to making any distributions on the units, we reimburse our general partner and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to make distributions to you. Our general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates provide us with services for which we are charged reasonable fees as determined by our general partner in its sole discretion. In December 2003, the $6.0 million limit on such reimbursements will expire and expenses will most likely be higher and reduce the amount of cash available for distribution on the units. See "Management—Reimbursement of Expenses of the General Partner" on page 89.

The control of our general partner may be transferred to a third party, and that third party could replace our current management team, in each case without unitholder consent.

The general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the owner of the general partner from transferring its ownership interest in the general partner to a third party. The new owner of the general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and to control the decisions taken by the board of directors and officers.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to our unitholders.

Our partnership agreement contains provisions which reduce the remedies available to unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to the unitholders. The partnership agreement also restricts the remedies available to unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. If you choose to purchase a common unit, you will be treated as having consented to the various actions contemplated in the partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary duties under applicable state law. See "Conflicts of Interest and Fiduciary Responsibilities" beginning on page 98.

We may issue additional common units without your approval, which would dilute your ownership interests.

During the subordination period, our general partner, without the approval of our unitholders, may cause us to issue up to 1,316,000 additional common units. Our general partner may also cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units in connection with acquisitions that increase cash flow from operations per unit on a pro forma basis;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances;
- the conversion of the general partner interest and the incentive distribution rights into common units as a result of the withdrawal of our general partner;
- issuances of common units under our long-term incentive plan; or
- issuances of common units to repay indebtedness, the cost of which to service is greater than the distribution obligations associated with the units issued in connection with the debt's retirement.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

After the end of the subordination period, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give

our unitholders the right to approve our issuance of equity securities ranking junior to the common units at any time.

Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time or price and may therefore not receive any return on your investment. You may also incur a tax liability upon a sale of your units. For additional information about the call right, please read "The Partnership Agreement—Limited Call Right" on page 115.

You may not have limited liability if a court finds that unitholder action constitutes control of our business.

You could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the "control" of our business, to the extent that a person who has transacted business with the partnership reasonably believes, based on your conduct, that you are a general partner. Our general partner generally has unlimited liability for the obligations of the partnership, such as its debts and environmental liabilities, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of that section may be liable to the limited partnership for the amount of the distribution for a period of three years from the date of the distribution. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Please read "The Partnership Agreement—Limited Liability" beginning on page 106 for a discussion of the implications of the limitations on liability to a unitholder.

Equity securities in Crosstex Energy Holdings Inc. eligible for future sale may have adverse effects on the price of our common units.

As of September 3, 2003, Crosstex Energy Holdings Inc. held 333,000 common units and 4,667,000 subordinated units, representing a 56% limited partnership interest in us after giving effect to this offering. Crosstex Energy Holdings' partnership interest in us represents substantially all of its assets. Crosstex Energy Holdings Inc. may, from time to time, issue equity securities or the present equity owners of Crosstex Energy Holdings Inc. may sell all or a portion of their equity securities in Crosstex Energy Holdings Inc. Sales of substantial amounts of equity securities in Crosstex Energy Holdings Inc., or the anticipation of such sales, could lower the market price of our common units and may make it more difficult for us to sell our equity securities in the future at a time and at a price that we deem appropriate.

Our common units have a limited trading history and a limited trading volume compared to other units representing limited partner interests.

Our common units are traded publicly on the Nasdaq National Market under the symbol "XTEX." However, our common units have a limited trading history and daily trading volumes for our common units are, and may continue to be, relatively small compared to many other units representing limited partner interests quoted on the Nasdaq National Market. Although we have several market makers in our common units, this alone does not assure significant trading volume or liquidity. We cannot assure

you that this offering will increase the trading volume for our common units, and the price of our common units may, therefore, be volatile.

Tax Risks to Our Unitholders.

You are urged to read "Material Tax Consequences" beginning on page 120 for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay tax on our income at corporate rates of up to 35% (under current law) and we would probably pay state income taxes as well. In addition, distributions to you would generally be taxed again to you as corporate distributions and no income, gains, losses, or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, the cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to you and thus would likely result in a material reduction in the value of the common units.

A change in current law or a change in our business could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state, or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be decreased to reflect the impact of that law on us.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units and the costs of any contest will be borne by us and, therefore, indirectly by our unitholders and our general partner.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel's conclusions expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with all of our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which common units trade. In addition, our costs of any contest with the IRS will be borne by us and therefore indirectly by our unitholders and our general partner.

You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

You will be required to pay federal income taxes and, in some cases, state, local, and foreign income taxes on your share of our taxable income even if you do not receive cash distributions from us. You may not receive cash distributions equal to your share of our taxable income or even the tax liability that results from that income.

Tax gain or loss on the disposition of our common units could be different than expected.

If you sell your common units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions in excess of the total net

taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, will likely be ordinary income to you. Should the IRS successfully contest some positions we take, you could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years. In addition, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Recent changes in federal income tax law could affect the value of our common units.

On May 28, 2003, the Jobs and Growth Tax Relief Reconciliation Act of 2003 was signed into law, which generally reduces the maximum tax rate applicable to corporate dividends to 15%. This reduction could materially affect the value of our common units in relation to alternative investments in corporate stock, as investments in corporate stock may be more attractive to individual investors thereby exerting downward pressure on the market price of our common units.

Tax-exempt entities, regulated investment companies, and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), regulated investment companies (known as mutual funds) and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business income and will be taxable to them. Very little of our income will be qualifying income to a regulated investment company or mutual fund. Distributions to non-U.S. persons will be reduced by withholding taxes, at the highest effective tax rate applicable to individuals, and non-U.S. persons will be required to file federal income tax returns and generally pay tax on their share of our taxable income.

We are registered as a tax shelter. This may increase the risk of an IRS audit of us or a unitholder.

We are registered with the IRS as a "tax shelter." Our tax shelter registration number is 02337000008. The tax laws require that some types of entities, including some partnerships, register as "tax shelters" in response to the perception that they claim tax benefits that may be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in our unitholders' tax returns and may lead to audits of unitholders' tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return.

We will determine the tax benefits that are available to an owner of units without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will take depreciation and amortization positions that may not conform to all aspects of the Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

As a result of investing in our common units, you will likely be subject to state and local taxes and return filing requirements in jurisdictions where you do not live.

In addition to federal income taxes, unitholders will likely be subject to other taxes such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. You will likely be required to file state, local and foreign income tax returns and pay state, local and foreign income taxes in some or all of the various jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. We own property or conduct business in Texas, Oklahoma, Louisiana, New Mexico, Arkansas, Mississippi and Alabama. Oklahoma, Louisiana, New Mexico, Arkansas, Mississippi and Alabama impose an income tax, generally. Texas does not impose a state income tax on individuals, but does impose a franchise tax on limited liability companies and corporations in certain circumstances. Texas does not impose a franchise tax on partnerships at this time. We may do business or own property in other states or foreign countries in the future. It is your responsibility to file all federal, state, local, and foreign tax returns. Our counsel has not rendered an opinion on the state, local, or foreign tax consequences of owning our common units.

USE OF PROCEEDS

We expect to receive net proceeds of approximately $50.1 million from the sale of the 1,500,000 common units offered by this prospectus, together with a capital contribution from our general partner of approximately $1.1 million to maintain its 2% general partner interest in our partnership, after deducting underwriting discounts and estimated offering expenses. We intend to use all of the net proceeds of this offering to repay a portion of the borrowings under the bank credit facility incurred in connection with recent acquisitions and capital projects, including the DEFS acquisition (for which we incurred borrowings of $67.3 million). Please read "Prospectus Summary—Recent Developments—Recent Acquisitions—Duke Energy Field Services" on page 2. We will use any net proceeds from the exercise of the over-allotment option to further repay borrowings under the bank credit facility.

As of June 30, 2003, total borrowings under the bank credit facility were approximately $68.0 million, and it had a weighted-average interest rate of 4.25%. The bank credit facility was amended in December 2003, in connection with our initial public offering, and in June 2003. The bank credit facility has a maturity date of June 1, 2006. Proceeds from the funds borrowed under the bank credit facility between July 2002 and June 2003 (totaling $108.9 million) were used for acquisitions, including the DEFS ($67.3 million), Vanderbilt system ($12.0 million) and Will-O-Mills ($2.2 million) acquisitions, and for capital projects, including the expansion of the Gregory processing plant ($5.3 million), improvements to the Vanderbilt system and related facilities ($3.0 million), the purchase, refurbishment and installation of treating plants, construction of a new gathering system and enhancements to, and maintenance of, existing assets ($19.1 million). In June 2003, $30.0 million of the outstanding borrowings under the bank credit facility was repaid with the proceeds of the issuance of senior secured notes.

CAPITALIZATION

The following table sets forth our capitalization as of June 30, 2003 on:

- a historical basis;
- a pro forma basis to give effect to the issuance of $10.0 million senior secured notes in July 2003 pursuant to the master shelf agreement; and
- a pro forma as adjusted basis to give effect to the common units offered by this prospectus, our general partner's proportionate capital contribution and the application of the net proceeds from this offering as described in "Use of Proceeds" on page 32.

You should read our financial statements and notes that are included elsewhere in this prospectus for additional information about our capital structure.

	As of June 30, 2003		
	Historical	Pro Forma	Pro Forma As Adjusted
	(in thousands)		
Cash and cash equivalents	$ 1,626	$ 1,626	$ 1,626
Debt:			
Bank debt & other	$ 68,750	$ 58,750	$ 7,527
Senior secured notes	30,000	40,000	40,000
Total debt	98,750	98,750	47,527
Partners' equity:			
Common unitholders	59,126	59,126	109,248
Subordinated unitholders	34,669	34,669	34,669
General partner interest	1,163	1,163	2,264
Other comprehensive income (loss)	(2,177)	(2,177)	(2,177)
Total partners' equity	92,781	92,781	144,004
Total capitalization	$ 191,531	$ 191,531	$ 191,531

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

Our common units are listed and traded on the Nasdaq National Market under the symbol "XTEX." Our common units began trading on December 12, 2002 at an initial public offering price of $20.00 per common unit. The following table shows the low and high closing sale prices per common unit, as reported by the Nasdaq National Market, for the periods indicated.

	Common Unit Price Range		Cash Distributions Per Unit
	Low	High	
2003:			
Quarter Ended September 30(a)	$ 33.25	$ 38.38	$ —(b)
Quarter Ended June 30	$ 24.36	$ 34.40	$ 0.550
Quarter Ended March 31	$ 21.48	$ 24.50	$ 0.576(c)
2002:			
Quarter Ended December 31	$ 20.10	$ 21.45	$ —

(a) Through September 3, 2003.

(b) For the quarter ended September 30, 2003, the board of directors of our general partner has authorized a distribution of $0.70 per unit, representing $0.20 in excess of the minimum quarterly distribution on all of our outstanding units.

(c) Reflects minimum quarterly distribution of $0.50 for the quarter ended March 31, 2003 and the pro rata portion of the $0.50 minimum quarterly distribution, covering the period from the December 17, 2002 closing of the initial public offering through December 31, 2002.

The last reported sale price of our common units on the Nasdaq National Market on September 3, 2003 was $35.97. As of August 15, 2003, there were approximately 2,740 holders of record of our common units.

CASH DISTRIBUTION POLICY

Distributions of Available Cash

General. Within approximately 45 days after the end of each quarter, we will distribute all of our available cash to unitholders of record on the applicable record date.

Definition of Available Cash. Available Cash means, for any quarter ending prior to liquidation:

- the sum of
  - all cash and cash equivalents of Crosstex Energy, L.P. and its subsidiaries on hand at the end of that quarter; and
  - all additional cash and cash equivalents of Crosstex Energy, L.P. and its subsidiaries on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made after the end of that quarter;
- less the amount of cash reserves that is necessary or appropriate in the reasonable discretion of the general partner to
  - provide for the proper conduct of the business of Crosstex Energy, L.P. and its subsidiaries (including reserves for future capital expenditures and for future credit needs of Crosstex Energy, L.P. and its subsidiaries) after that quarter;
  - comply with applicable law or any debt instrument or other agreement or obligation to which Crosstex Energy, L.P. or any of its subsidiaries is a party or its assets are subject; and
  - provide funds for minimum quarterly distributions and cumulative common unit arrearages for any one or more of the next four quarters;

provided, however, that the general partner may not establish cash reserves for distributions to the subordinated units unless the general partner has determined that, in its judgment, the establishment of reserves will not prevent Crosstex Energy, L.P. from distributing the minimum quarterly distribution on all common units and any cumulative common unit arrearages thereon for the next four quarters; and

provided, further, that disbursements made by Crosstex Energy, L.P. or any of its subsidiaries or cash reserves established, increased or reduced after the end of that quarter but on or before the date of determination of available cash for that quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if the general partner so determines.

Minimum Quarterly Distribution. Common units are entitled to receive distributions from operating surplus of $0.50 per quarter, or $2.00 on an annualized basis, before any distributions are paid on our subordinated units. There is no guarantee that we will pay the minimum quarterly distribution on the common units in any quarter, and we will be prohibited from making any distributions to unitholders if it would cause a default or an event of default under our bank credit facility or the senior secured notes.

Contractual Restrictions on our Ability to Distribute Available Cash. Our ability to distribute available cash is contractually restricted by the terms of our bank credit facility and our senior secured notes. The bank credit facility and the our senior secured notes contain covenants requiring us to maintain certain financial ratios, such as debt to EBITDA, EBITDA to interest expense and current assets to current liabilities. We are prohibited from making any distribution to unitholders if such distribution would cause a default or an event of default under the bank credit facility or the senior secured notes. The bank credit facility and the master shelf agreement governing the senior secured

notes limit the use of borrowings under the bank credit facility to make distributions to unitholders to $5.0 million over the term of the bank credit facility.

Operating Surplus and Capital Surplus

General. All cash distributed to unitholders will be characterized either as "operating surplus" or "capital surplus." We distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus. We define operating surplus in the glossary, and for any period it generally means:

- our cash balance of $7.2 million at the closing of our initial public offering; plus
- $8.9 million (as described below); plus
- all of our cash receipts since the initial public offering, excluding cash from borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus
- working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; less
- all of our operating expenditures since the initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures, and less

- the amount of cash reserves that the general partner deems necessary or advisable to provide funds for future operating expenditures.

As reflected above, our definition of operating surplus includes $8.9 million in addition to our cash balance of $7.2 million at the closing of our initial public offering, cash receipts from our operations and cash from working capital borrowings. This amount does not reflect actual cash on hand at closing that is available for distribution to our unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to $8.9 million of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities and long-term borrowings, that would otherwise be distributed as capital surplus.

Definition of Capital Surplus. We also define capital surplus in the glossary, and it will generally be generated only by:

- borrowings other than working capital borrowings;
- sales of debt and equity securities; and
- sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

Characterization of Cash Distributions. We will treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since we began operations equals the operating surplus as of the most recent date of determination of available cash. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. While we do not currently anticipate that we will make any distributions from capital surplus in the near term, we may determine that the sale or disposition of an asset or business owned or acquired by us may be beneficial to our unitholders. If we distribute to you the equity we own in a subsidiary or the proceeds

from the sale of one of our businesses, such a distribution would be characterized as a distribution from capital surplus.

Subordination Period

General. During the subordination period, which we define below and in the glossary, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.50 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Definition of Subordination Period. We define the subordination period in the glossary. The subordination period will extend until the first day of any quarter beginning after December 31, 2007 that each of the following tests are met:

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

Early Conversion of Subordinated Units. Before the end of the subordination period, a portion of the subordinated units may convert into common units on a one-for-one basis immediately after the distribution of available cash to partners in respect of any quarter ending on or after:

- December 31, 2005 with respect to 25% of the subordinated units; and
- December 31, 2006 with respect to 25% of the subordinated units.

The early conversions will occur if at the end of the applicable quarter each of the following three tests are met:

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

However, the early conversion of the second 25% of the subordinated units may not occur until at least one year following the early conversion of the first 25% of the subordinated units.

Definition of Adjusted Operating Surplus. We define "adjusted operating surplus" in the glossary, and for any period it generally means:

- operating surplus generated with respect to that period; less

- any net increase in working capital borrowings with respect to that period; less
- any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus
- any net decrease in working capital borrowings with respect to that period; and plus
- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted Operating Surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods.

Effect of Expiration of the Subordination Period. Upon expiration of the subordination period, each outstanding subordinated unit will convert into one common unit and will then participate, pro rata, with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and units held by our general partner and its affiliates are not voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately convert into one common unit on a one-for-one basis;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Distributions of Available Cash from Operating Surplus During the Subordination Period

We will make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

- *First,* 98% to the common unitholders, pro rata, and 2% to our general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;
- *Second,* 98% to the common unitholders, pro rata, and 2% to our general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;
- *Third,* 98% to the subordinated unitholders, pro rata, and 2% to our general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and
- *Thereafter,* in the manner described in "—Incentive Distribution Rights" on the next page.

Distributions of Available Cash from Operating Surplus After the Subordination Period

We will make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

- *First,* 98% to all unitholders, pro rata, and 2% to our general partner until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and
- *Thereafter,* in the manner described in "—Incentive Distribution Rights" below.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner in the following manner:

- *First,* 85% to all unitholders, pro rata, 13% to the holders of the incentive distribution rights, pro rata, and 2% to our general partner until each unitholder receives a total of $0.625 per unit for that quarter (the "first target distribution");
- *Second,* 75% to all unitholders, pro rata, 23% to the holders of the incentive distribution rights, pro rata, and 2% to our general partner, until each unitholder receives a total of $0.75 per unit for that quarter (the "second target distribution"); and
- *Thereafter,* 50% to all unitholders, pro rata, 48% to the holders of the incentive distribution rights, pro rata, and 2% to our general partner.

In each case, the amount of the target distribution set forth above is exclusive of any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution.

Target Amount of Quarterly Distribution

The following table illustrates the percentage allocations of the additional available cash from operating surplus among the unitholders, our general partner and the holders of the incentive distribution rights up to the various target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our unitholders, our general partner and the holders of the incentive distribution rights in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Target Amount," until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for the unitholders and our general

partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

		Marginal Percentage Interest in Distributions		
	Total Quarterly Distribution Target Amount	**Unitholders**	**General Partner**	**Holders of Incentive Distribution Rights**
Minimum Quarterly Distribution	$0.50	98%	2%	—
First Target Distribution	above $0.50 up to $0.625	85%	2%	13%
Second Target Distribution	above $0.625 up to $0.75	75%	2%	23%
Thereafter	above $0.75	50%	2%	48%

Distributions from Capital Surplus

How Distributions from Capital Surplus will be Made. We will make distributions of available cash from capital surplus in the following manner:

- *First,* 98% to all unitholders, pro rata, and 2% to our general partner, until we distribute for each common unit that was issued in the initial public offering, an amount of available cash from capital surplus equal to the initial public offering price;

- *Second,* 98% to the common unitholders, pro rata, and 2% to our general partner, until we distribute for each common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and

- *Thereafter,* we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Effect of a Distribution from Capital Surplus. The partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from the initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to as the "unrecovered initial unit price." Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution, after any of these distributions are made, it may be easier for our general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we distribute capital surplus on a unit issued in this offering in an amount equal to the initial unit price, we will reduce the minimum quarterly distribution and the target distribution levels to zero. We will then make all future distributions from operating surplus, with 50% being paid to the holders of units, 48% to the holders of incentive distribution rights and 2% to our general partner.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units we will proportionately adjust:

- the minimum quarterly distribution;

- target distribution levels;

- unrecovered initial unit price;

- the number of common units issuable during the subordination period without a unitholder vote; and

- the number of common units into which a subordinated unit is convertible.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50% of its initial level. We will not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted in a manner that causes us to become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, we will reduce the minimum quarterly distribution and the target distribution levels by multiplying the same by one minus the sum of the highest marginal federal corporate income tax rate that could apply and any increase in the effective overall state and local income tax rates. For example, if we became subject to a maximum marginal federal, and effective state and local income tax rate of 38%, then the minimum quarterly distribution and the target distributions levels would each be reduced to 62% of their previous levels.

Distributions of Cash upon Liquidation

General. If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called a liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and our general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of our general partner.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will allocate any gain to the partners in the following manner:

- *First,* to our general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;
- *Second,* 98% to the common unitholders, pro rata, and 2% to our general partner, until the capital account for each common unit is equal to the sum of:

  (1) the unrecovered initial unit price;

  (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and

  (3) any unpaid arrearages in payment of the minimum quarterly distribution on that common unit;

- *Third,* 98% to the subordinated unitholders, pro rata, and 2% to our general partner, until the capital account for each subordinated unit is equal to the sum of:

  (1) the unrecovered initial unit price; and

  (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

- *Fourth,* 85% to all unitholders, pro rata, 13% to the holders of incentive distribution rights, pro rata, and 2% to our general partner until we allocate under this paragraph an amount per unit equal to:

  (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less

  (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 85% to the unitholders, pro rata, and 15% to our general partner for each quarter of our existence;

- *Fifth,* 75% to all unitholders, pro rata, 23% to the holders of incentive distribution rights, pro rata, and 2% to our general partner, until we allocate under this paragraph an amount per unit equal to:

  (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less

  (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 75% to the unitholders, pro rata, and 25% to our general partner for each quarter of our existence;

- *Thereafter,* 50% to all unitholders, pro rata, 48% to the holders of the incentive distribution rights, pro rata, and 2% to our the general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

Manner of Adjustments for Losses. Upon our liquidation, we will generally allocate any loss to our general partner and the unitholders in the following manner:

- *First,* 98% to holders of subordinated units in proportion to the positive balances in their capital accounts and 2% to our general partner until the capital accounts of the subordinated unitholders have been reduced to zero;
- *Second,* 98% to the holders of common units in proportion to the positive balances in their capital accounts and 2% to our general partner until the capital accounts of the common unitholders have been reduced to zero; and
- *Thereafter,* 100% to our general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

Adjustments to Capital Accounts. We will make adjustments to capital accounts upon the issuance of additional units. In doing so, we will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and our general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, we will allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in our general partner's capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table sets forth selected historical financial and operating data for Crosstex Energy, L.P. and our predecessor, Crosstex Energy Services, Ltd., as of and for the dates and periods indicated and selected pro forma financial and operating data for Crosstex Energy, L.P. as of and for the year ended December 31, 2002 and the six months ended June 30, 2003. The summary historical financial data for the year ended December 31, 1998 and 1999, the four months ended April 30, 2000, the eight months ended December 31, 2000, and the years ended December 31, 2001 and 2002 are derived from our audited financial statements of Crosstex Energy, L.P. and its predecessor. The summary historical financial data for the six months ended June 30, 2002 and 2003 are derived from our unaudited financial statements and, in our opinion, have been prepared on the same basis as the audited financial statements and include all adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of this information. As described in our historical financial statements, the investment in our predecessor by Yorktown Energy Partners IV, L.P. in May 2000 resulted in the dissolution of the predecessor partnership and the creation of a new partnership with the same organization, purpose, assets and liabilities. Accordingly, the audited financial statements for 2000 are divided into the four months ended April 30, 2000 and the eight months ended December 31, 2000 because a new basis of accounting was established effective May 1, 2000 to give effect to the Yorktown transaction. In addition, the summary historical financial and operating data include the results of operations of the Arkoma system beginning in September 2000, the Gulf Coast system beginning in September 2000 and the CCNG system, which includes the Corpus Christi system, the Gregory gathering system and the Gregory processing plant, beginning in May 2001.

The selected pro forma financial and operating data reflect our consolidated historical operating results as adjusted for the DEFS acquisition, the senior secured note offerings, this offering and, in the case of the pro forma statement of operations for the year ended December 31, 2002, our initial public offering. The selected pro forma financial data is derived from the unaudited pro forma financial statements. The pro forma balance sheet assumes that the issuance of $10.0 million of senior secured notes and this offering occurred on June 30, 2003. The pro forma statements of operations assume that the DEFS acquisition, the senior secured note offerings, this offering and our initial public offering occurred on January 1, 2002. For a description of all of the assumptions used in preparing the summary pro forma financial data, you should read the notes to the pro forma financial statements. The pro forma financial and operating data should not be considered as indicative of the historical results we would have had or the future results that we will have after the offering.

We derived the information in the following table from, and that information should be read together with, and is qualified in its entirety by reference to, the historical and pro forma financial statements and the accompanying notes included in this prospectus. The table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 47.

	Crosstex Energy, L.P.(1)									
	Predecessor			Historical					Pro Forma as Adjusted	
							Unaudited		Unaudited	
	Years Ended December 31,		Four Months Ended April 30,	Eight Months Ended December 31,	Year Ended December 31,	Year Ended December 31,	Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	1998	1999	2000	2000	2001	2002	2002	2003	2002	2003
	(in thousands, except per unit amounts and operating data)									
Statement of Operations Data:										
Revenues:										
Midstream	$ 7,181	$ 7,896	$ 3,591	$ 88,008	$ 362,673	$ 437,676	$ 200,595	$ 469,345	$ 574,757	$575,667
Treating	1,647	9,770	5,947	17,392	24,353	14,817	6,878	10,477	14,817	10,477
Total revenues	8,828	17,666	9,538	105,400	387,026	452,493	207,473	479,822	589,574	586,144
Operating costs and expenses:										
Midstream purchased gas	5,561	5,154	2,746	83,672	344,755	413,982	189,675	451,479	534,839	549,317
Treating purchased gas	1,025	8,110	4,731	14,876	18,078	5,767	2,599	4,451	5,767	4,451
Operating expenses	871	986	544	1,796	7,430	10,468	5,050	6,545	15,661	9,643
General and administrative(2)	2,006	2,078	810	2,010	5,914	8,454	4,206	3,391	6,000	3,391
Stock based compensation	—	—	8,802	—	—	41	—	3,072	41	3,072
Impairments	—	538	—	—	2,873	4,175	3,150	—	4,175	—
(Profit) loss on energy trading	(1,402)	(1,764)	(638)	(1,253)	3,714	(2,703)	(2,754)	(845)	(2,703)	(845)

Depreciation and amortization	843	1,286	522	2,261	6,101	7,745	3,884	5,046	12,180	7,339
Total operating costs and expenses	8,904	16,388	17,517	103,362	388,865	447,929	205,810	473,139	575,960	576,368
Operating income (loss)	(76)	1,278	(7,979)	2,038	(1,839)	4,564	1,663	6,683	13,614	9,776
Other income (expense):										
Interest expense, net	(502)	(638)	(79)	(530)	(2,253)	(2,717)	(1,696)	(875)	(3,281)	(1,828)
Other income (expense)	88	(138)	381	115	174	155	5	(1)	155	(1)
Total other income (expense)	(414)	(776)	302	(415)	(2,079)	(2,562)	(1,691)	(876)	(3,126)	(1,829)
Net income (loss)	$ (490)	$ 502	$ (7,677)	$ 1,623	$ (3,918)	$ 2,002	$ (28)	$ 5,807	$ 10,488	$ 7,947
Net income per limited partner unit(3)	N/A	N/A	N/A	N/A	N/A	$ 0.04	N/A	$ 0.77	$ 1.17	$ 0.88
Balance Sheet Data (at period end):										
Working capital surplus (deficit)	$ (3,394)	$ (3,483)	$ (4,005)	$ 5,861	$ (2,254)	$ (8,672)	$ (8,672)	$ (11,019)		$ (11,019)
Property and equipment, net	10,103	8,072	10,540	37,242	84,951	109,948	109,948	188,986		188,986
Total assets	37,223	36,497	45,051	201,268	168,376	232,438	232,438	352,565		352,565
Total debt	6,589	5,389	7,000	22,000	60,000	22,550	22,500	98,750		47,527
Partners' equity	2,655	3,242	3,608	40,354	41,155	89,816	89,816	92,781		144,004
Cash Flow Data:										
Net cash flow provided by (used in):										
Operating activities	$ 3,963	$ 1,404	$ 7,380	$ 7,741	$ (8,326)	$ 19,956	$ 27,084	$ 15,141		
Investing activities	(4,821)	(1,342)	(2,849)	(25,643)	(52,535)	(33,240)	(10,337)	(85,238)		
Financing activities	1,437	(857)	198	36,557	42,558	14,240	(2,700)	70,415		
Other Financial Data:										
Midstream gross margin	$ 1,620	$ 2,742	$ 845	$ 4,336	$ 17,918	$ 23,694	$ 10,920	$ 17,866	$ 39,918	$ 26,350
Treating gross margin	622	1,660	1,216	2,516	6,275	9,050	4,279	6,026	9,050	6,026
Total gross margin(4)	2,242	4,402	2,061	6,852	24,193	32,744	15,199	23,892	48,968	32,376
EBITDA(5)	855	2,426	(7,076)	4,414	4,436	12,464	5,552	11,728	25,949	17,114
Maintenance capital expenditures				57	1,922	2,350	592	1,719		
Expansion capital expenditures				25,743	50,766	30,980	9,813	82,873		
Total capital expenditures(6)				$ 25,800	$ 52,688	$ 33,330	$ 10,405	$ 84,592		
Operating Data (MMBtu/d):										
Pipeline throughput	16,435	19,712	23,098	104,185	313,103	392,681	386,110	504,447	501,233	603,160
Natural gas processed	13,394	23,112	30,699	15,661	60,629	85,776	89,279	93,654	118,239	123,438
Treating volumes(7)	3,982	12,896	26,872	35,910	62,782	97,866	95,895	88,994	97,866	88,994

(1) Crosstex Energy Services, Ltd. is the predecessor to Crosstex Energy, L.P. Results of operations and balance sheet data prior to May 1, 2000 represent historical results of the predecessor to Crosstex Energy Services, Ltd. These results are not necessarily comparable to the results of Crosstex Energy Services, Ltd. subsequent to May 2000 due to the new basis of accounting.

(2) For the twelve month period ending in December 2003, the amount for which general partner is entitled to reimbursement from us for allocated general and administrative expenses is limited to $6.0 million. Such limitaiton does not apply to expenses incurred in connection with acquisition or business development opportunities evaluated on our behalf.

(3) Net income (loss) per limited partner unit is not applicable for periods prior to our initial public offering. Net income per unit of $0.04 for the year ended December 31, 2002 represents allocation of our 2002 net income for the period from December 17, 2002 to December 31, 2002.

(4) Gross margin is defined as revenue less related cost of purchased gas.

(5) We define EBITDA as net income (loss) plus interest expense, provision for income taxes and depreciation and amortization expense. EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (a) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis; (b) our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing and capital structure; and (c) the viability of projects and the overall rates of return on alternative investment opportunities. EBITDA should not be considered an alternative to net income; operating income, cash flow from operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA is not intended to represent cash flow. Because EBITDA excludes some, but not all,

items that affect net income and these measures may vary among other companies, the EBITDA data presented may not be comparable to similarly titled measures of other companies.

The following table reconciles EBITDA to net income (loss):

Crosstex Energy, L.P.		
Predecessor	**Historical**	**Pro Forma as Adjusted**
	Unaudited	**Unaudited**

	Years Ended December 31,		Four Months Ended April 30,	Eight Months Ended December 31,	Year Ended December 31,	Year Ended December 31,	Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	1998	1999	2000	2000	2001	2002	2002	2003	2002	2003
	(in thousands, except per unit amounts and operating data)									
EBITDA Reconciliation:										
Net income (loss)	$ (490)	$ 502	$ (7,677)	$ 1,623	$ (3,918)	$ 2,002	$ (28)	$ 5,807	$ 10,488	$ 7,947
Plus:										
Depreciation and amortization	843	1,286	522	2,261	6,101	7,745	3,884	5,046	12,180	7,339
Interest expense, net	502	638	79	530	2,253	2,717	1,696	875	3,281	1,828
EBITDA	$ 855	$ 2,426	$ (7,076)	$ 4,414	$ 4,436	$ 12,464	$ 5,552	$ 11,728	$ 25,949	$ 17,114

Our predecessors were partnerships and had no income tax expense. EBITDA for the years ended December 31, 1999, 2001 and 2002 and the six months ended June 30, 2002 has been reduced by non-cash impairment charges of $0.5 million, $2.9 million, $4.2 million and $3.2 million, respectively, and the six months ended June 30, 2003 has been reduced by non-cash stock-based compensation charges of $3.1 million.

(6) Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives. Expansion capital expenditures are capital expenditures made to expand the existing operating capacity of our assets, whether through construction or acquisition. We treat repair and maintenance expenditures that do not extend the useful life of existing assets as operating expenses as we incur them.

(7) Represents volumes for treating plants operated by us whereby we receive a fee based on the volumes treated.

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 historical and pro forma combined financial statements and notes thereto included elsewhere in this prospectus. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the historical and pro forma financial statements included in this prospectus.

Overview

We are a Delaware limited partnership formed by Crosstex Energy Holdings Inc. on July 12, 2002 to acquire indirectly substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas, as well as providing certain producer services, while our Treating division focuses on the removal of carbon dioxide and hydrogen sulfide from natural gas to meet pipeline quality specifications. For the six months ended June 30, 2003, 74.8% of our gross margin was generated in the Midstream division, with the balance in the Treating division, and approximately 78.2% of our gross margin was generated in the Texas Gulf Coast region.

Since our formation, we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines, treating plants and processing plants. From January 1, 2000 through June 30, 2003, we have invested approximately $199.4 million to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods throughout the year and were accounted for under the purchase method of accounting for business combinations. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our results of operations are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities or treated at our treating plants. We generate revenues from four primary sources:

- gathering and transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants;
- providing producer services; and
- treating natural gas at our treating plants.

The bulk of our operating profits are derived from the margins we realize for gathering and transporting natural gas through our pipeline systems. Generally, we buy gas from a producer, plant tailgate, or transporter at either a fixed discount to a market index or a percentage of the market index. We then transport and resell the gas. The resale price is based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. Set forth in the table below is the volume of the natural gas purchased and sold at a fixed discount or premium to the index price and at a percentage discount or premium to the index price for our principal gathering and transmission

systems and for our producer services business for the year ended December 31, 2002 and the six months ended June 30, 2003.

	Year Ended December 31, 2002		Six Months Ended June 30, 2003	
	Gas Purchased	Gas Sold	Gas Purchased	Gas Sold

Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(in billions of MMBtus)				(in billions of MMBtus)			
Gulf Coast system	34.7	3.0	37.7	—	14.3	1.1	15.4	—
Vanderbilt system(1)	—	—	—	—	2.9	4.5	7.4	—
CCNG transmission system	57.4	0.3	57.7	—	29.6	0.2	29.8	—
Gregory gathering system(1)	35.8	3.2	31.9	—	24.9	1.1	22.4	—
Arkoma gathering system	—	3.9	3.9	—	—	1.9	1.9	—
Producer services(2)	81.2	2.9	84.1	—	45.2	1.5	46.7	—
	209.1	13.3	215.3	—	116.9	10.3	123.6	—

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

(2) These volumes are not reflected in revenues or purchased gas cost, but are presented net as a component of profit (loss) on energy trading activities in accordance with EITF 02-03.

We estimate that, due to the gas that we purchase at a percentage of index price, for each $0.50 per MMBtu increase or decrease in the price of natural gas, our gross margins increase or decrease by approximately $0.7 million on an annual basis (before consideration of the hedges discussed below). We have hedged a portion of our exposure to such fluctuations in natural gas prices as follows for future periods:

Period	Volume Hedged (MMBtu per month)	Weighted-Average Price per MMBtu
3rd quarter of 2003	130,000	$ 3.97
4th quarter of 2003	100,000	5.31
1st quarter of 2004	90,000	5.11
2nd quarter of 2004	70,000	4.97
3rd quarter of 2004	30,000	4.85
4th quarter of 2004	30,000	4.85

We expect to continue to hedge our exposure to gas production which we purchase at a percentage of index when market opportunities appear attractive.

In addition to the margins generated by the Gregory gathering system, we generate revenues at our Gregory processing plant under two types of arrangements:

- For the year ended December 31, 2002 and the six months ended June 30, 2003, we purchased approximately 44% and 22%, respectively, of the natural gas volumes on our Gregory system under contracts in which we were exposed to the risk of loss or gain in processing the natural gas. Under these contracts, we fractionate the NGLs into separate NGL products, which we then sell at prices based upon the market price for NGL products. The processed natural gas is sold at a price based on a fixed price relative to a monthly index, with the first 100,000 MMBtu of processed natural gas being sold to a subsidiary of Kinder Morgan. Since we extract Btus from the gas stream in the form of the liquids or consume it as fuel during processing, we reduce the Btu content of the natural gas but seek to more than offset this by creating value from the separated NGL products. Accordingly, our margins under these arrangements can be negatively affected in periods where the value of natural gas is high relative to the value of NGLs.

- For the year ended December 31, 2002 and the six months ended June 30, 2003, we purchased approximately 56% and 78%, respectively, of the natural gas volumes on our 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 our Gregory processing plant with no risk of loss or gain in processing the natural gas. Under these contracts, the producer retains ownership of the fractionated NGLs, and accordingly bears the risk and retains the benefits associated with processing the natural gas.

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

We own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon dioxide under a long-term arrangement. Revenues at the plant are derived from a fee it charges producers, including those at the Seminole San Andres unit, for each Mcf of carbon dioxide returned to the producer for reinjection. The fees currently average $0.5834 for each Mcf of carbon dioxide returned. Reinjected carbon dioxide is used in a tertiary oil recovery process in the field. The plant also receives 50% of the NGLs produced by the plant. We have entered into a one-year contract with Duke Energy NGL Services, L.P. to market our NGLs on our behalf, and receive our share of proceeds from the sale of carbon dioxide from the plant operator. We are separately billed by the plant operator for our share of expenses.

We generate producer services revenues through the purchase and resale of natural gas. We currently purchase for resale volumes of natural gas that do not move through our gathering, processing or transmission assets from over 50 independent producers. We engage in such activities on more than 30 interstate and intrastate pipelines with a major emphasis on Gulf Coast pipelines. We focus on supply aggregation transactions in which we either purchase and resell gas and thereby eliminate the need of the producer to engage in the marketing activities typically handled by in-house marketing or supply departments of larger companies, or act as agent for the producer.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 66% and 63% of the operating income in our Treating division for the year ended December 31, 2002 and the six months ended June 30, 2003, respectively;

- a fixed fee for operating the plant for a certain period, which accounted for approximately 22% and 30% of the operating income in our Treating division for the year ended December 31, 2002 and the six months ended June 30, 2003, respectively; or

- a fee arrangement in which the producer operates the plant, which accounted for approximately 12% and 7% of the operating income in our Treating division for the year ended December 31, 2002 and the six months ended June 30, 2003, respectively.

Typically, we incur minimal incremental operating or administrative overhead costs when gathering and transporting additional natural gas through our pipeline assets.

Therefore, we recognize a substantial portion of incremental gathering and transportation revenues as operating income.

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

Our general and administrative expenses are dictated by the terms of our partnership agreement and our omnibus agreement with Crosstex Energy Holdings Inc. Our general partner and its affiliates are reimbursed for expenses incurred on our behalf. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to Crosstex Energy, L.P., and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, Crosstex Energy, L.P. Our partnership agreement provides that our general partner determines the expenses that are allocable to Crosstex Energy, L.P. in any reasonable manner determined by our general partner in its sole discretion. For the twelve month period ending in December 2003, the amount which we will reimburse our general partner and its affiliates for costs incurred with respect to the general and administrative services performed on our behalf will not exceed $6.0 million. This reimbursement cap does not apply to the cost of any third-party legal, accounting or advisory services received, or the direct expenses of management incurred, in connection with acquisition or business development opportunities evaluated on our behalf. On December 31, 2003, the $6.0 million limit on such reimbursements will expire and expenses will most likely be higher.

Crosstex Energy Holdings Inc. modified certain terms of a portion of its outstanding options in the first quarter of 2003. These modifications resulted in variable award accounting for the modified options. Total compensation expense was approximately $3.1 million, which has been recorded by Crosstex Energy, L.P. as non-cash stock based compensation expense in the six months ended June 30, 2003. Compensation expense in future periods will be adjusted for changes in the unit market price.

As described in the historical financial statements, the investment in our predecessor by Yorktown Energy Partners IV, L.P. in May 2000 resulted in the dissolution of the predecessor partnership, and the creation of a new partnership with the same organization, purpose, assets, and liabilities. The transaction value of $21.9 million from the Yorktown investment was allocated to the assets and liabilities of our predecessor, which created increases in depreciation and amortization charges in periods subsequent to the Yorktown investment. The historical financial statements present separate reports for the entities before and after the transaction. For purposes of the analysis below, the year 2000 is considered one period, and the distinction in legal entities created by the transaction with Yorktown is ignored.

We have grown significantly through asset purchases in recent years, which creates many of the major differences when comparing operating results from one period to another. The most significant asset purchases are the acquisitions of the Arkoma gathering system, the Gulf Coast system, the CCNG system, the Vanderbilt system and the DEFS acquisition (which will not be reflected in our historical results of operations until after June 30, 2003).

We acquired the Arkoma gathering system in September 2000 for a purchase price of approximately $10.5 million. The Arkoma system consisted of approximately 84 miles of gathering lines located in eastern Oklahoma. When acquired, the system was connected to approximately 115 wells, and purchased and resold approximately 12,000 MMBtu of gas per day.

We acquired the Gulf Coast system in September 2000 for a purchase price of approximately $10.6 million. The Gulf Coast system consisted of approximately 484 miles of gathering and transmission lines extending from south Texas to markets near the Houston area. At the time of the acquisition, it was transporting approximately 117,000 MMBtu of gas per day.

We acquired the CCNG system in May 2001 for a purchase price of approximately $30 million. The CCNG system included four principal assets: the Corpus Christi system, the Gregory gathering system, the Gregory processing plant and the Rosita treating plant.

- The Corpus Christi system consists of approximately 295 miles of gathering and transmission lines extending from supply points in south Texas to markets in Corpus Christi Texas, with average throughput of approximately 152,000 MMBtu of gas per day at the time of the acquisition.

- The Gregory gathering system consists of approximately 297 miles of gathering lines located primarily in the Corpus Christi Bay area, with average throughput of approximately 76,500 MMBtu of gas per day at the time of the acquisition.

- The Gregory processing plant processes most of the gas gathered by the Gregory gathering system, extracting the liquids, fractionating them into NGLs, and selling the remaining residue gas. At the time of the acquisition, the plant was processing approximately 43,400 MMBtu of gas per day.

- The Rosita treating plant was treating approximately 25,000 MMBtu of gas per day at the time of its acquisition. The Rosita treating plant is operated in the Treating Division, whereas all of the other assets in the CCNG acquisition are included in the Midstream Division.

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

Certain assets and liabilities of our predecessor were not contributed to us. These include receivables associated with the Enron Corp. bankruptcy discussed on page 57 under "—Results of Operations—Year Ended December 31, 2001 Compared to Year Ended December 31, 2000—Profit (Loss) on Energy Trading." In addition, the Jonesville processing plant, which had been largely inactive since the beginning of 2001, and the Clarkson plant, acquired shortly before our initial public offering, were not contributed to us.

Commodity Price Risks

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

Profitability under our gas processing contracts is impacted by the margin between NGL sales prices and the cost of natural gas and may be negatively affected by decreases in NGL prices or increases in natural gas prices.

Changes in natural gas prices impact our profitability since the purchase price of a portion of the gas we buy (approximately 8.1% in the first six months of 2003) 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, on this portion of the gas, the changes are equal and offsetting.

Part of our fee from the Seminole gas plant is based on a portion of the NGLs produced, and, therefore, is subject to commodity price risks.

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

Results of Operations

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

	Year Ended December 31,			Six Months Ended June 30,	
	2000	2001	2002	2002	2003
			(in millions)		
Midstream revenues	$ 91.6	$ 362.7	$ 437.7	$ 200.6	$ 469.3
Midstream purchased gas	86.4	344.8	414.0	189.7	451.5
Midstream gross margin	5.2	17.9	23.7	10.9	17.8
Treating revenues	23.3	24.4	14.8	6.9	10.5
Treating purchased gas	19.6	18.1	5.8	2.6	4.5
Treating gross margin	3.7	6.3	9.0	4.3	6.0
Total gross margin	$ 8.9	$ 24.2	$ 32.7	$ 15.2	$ 23.8
Midstream Volumes (MMBtu/d):					
Gathering and transportation	77,527	313,103	392,681	386,110	504,477
Processing	20,605	60,629	85,776	89,279	93,654
Producer services	215,121	283,098	230,327	230,735	258,064
Treating Volumes (MMBtu/d)	32,938	62,782	97,866	95,895	88,994

Six Months Ended June 30, 2003 Compared to Six Months Ended June 30, 2002

Revenues. Midstream revenues were $469.3 million for the six months ended June 30, 2003 compared to $200.6 million for the six months ended June 30, 2002, an increase of $268.8 million, or 134%. An increase in natural gas prices from an average NYMEX settlement price of $2.86 per MMBtu for the first six months of 2002 to $5.80 per MMBtu in the first six months of 2003 resulted in a $136.8 million increase in revenues. An additional $97.6 million of revenues were generated in the first six months of 2003 by the Vanderbilt system and the Hallmark lateral that were not in operation in the first six months of 2002. Additional increases in revenues of $38.2 million and $7.6 million were generated from the Gregory gathering system and the Gregory processing plant, respectively, due to new volumes from producer drilling. Additional revenues of $2.2 million were generated from the Corpus Christi system due to new markets adding volumes to the system. These increases were partially offset by a decrease in revenues of $11.3 million from the Gulf Coast system and the Arkoma gathering system due to a decrease in volumes.

Treating revenues were $10.5 million for the six months ended June 30, 2003 compared to $6.9 million in the same period in 2002, an increase of $3.6 million, or 52%. Increases in the price of natural gas contributed $4.7 million of the increase, and $1.9 million of the increase was due to 20 new treating plants placed in service. These increases were partially offset by volume decreases at three treating plants, which reduced revenues by $2.4 million and the removal of 10 treating plants from service which reduced revenues by $0.7 million.

Purchased Gas Costs. Midstream purchased gas costs were $451.5 million for the six months ended June 30, 2003 compared to $189.7 million for the six months ended June 30, 2002, an increase of $261.8 million, or 138%. Costs increased by $135.2 million due to the increase in natural gas prices. In addition, costs of $94.6 million were generated by the Vanderbilt system and the Hallmark lateral that were not in operation in the first six months of 2002. Additional costs were incurred at the Gregory gathering system of $35.6 million and at the Gregory processing plant of $7.4 million due to new volumes from producer drilling. Additional costs of $2.2 million were generated from the Corpus

Christi system due to volume added to fulfill new market demands. These increases in costs were partially offset by a decrease in purchased gas costs of $11.1 million from the Gulf Coast system and the Arkoma gathering system due to a decrease in volumes.

Treating purchased gas costs were $4.5 million for the six months ended June 30, 2003 compared to $2.6 million in the comparable period in 2002, an increase of $1.9 million, or 71%. The increase in natural gas prices resulted in a $4.2 million increase, which was partially offset by a decrease in treating volumes at three volume sensitive plants.

Operating Expenses. Operating expenses were $6.5 million for the six months ended June 30, 2003, compared to $5.1 million for the six months ended June 30, 2002, an increase of $1.5 million, or 30%. This increase was primarily due to the initiation of service from the Vanderbilt system and the Hallmark lateral, and new treating plants placed in service.

General and Administrative Expenses. General and administrative expenses were $3.4 million for the six months ended June 30, 2003 compared to $4.2 million for the six months ended June 30, 2002, a decrease of $0.8 million, or 19%. The decrease was due to the $6.0 million annual general and administrative cap for the twelve months following our initial public offering, per the partnership agreement. Had the cap not been in place, general and administrative expenses would have been $4.6 million for the six months ended June 30, 2003.

Stock-based Compensation. Stock-based compensation was $3.1 million for the six months ended June 30, 2003, compared to none in the same period of 2002. This stock-based compensation primarily related to a modification in employee option agreements, which allowed the option holders to elect to be paid in cash for the modified options based on the fair value of those options.

Impairments. There was no impairment expense in the first six months 2003 compared to $3.2 million in the first six months of 2002. Intangible assets were booked associated with the contract values of certain treating plants and other assets in conjunction with the Yorktown investment in May 2000. Impairment charges in the first six months of 2002 were associated with intangible contract values at two specific treating plants. These two plants are still working at the location where they were sited at the time of the Yorktown investment, but had experienced declines in cash flows at the time the impairment charges were taken.

(Profit) Loss on Energy Trading. The profit on energy trading was $0.8 million for the six months ended June 30, 2003 compared to $2.8 million for the six months ended June 30, 2002, a decrease of $1.9 million. Included in these amounts were realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $0.8 million in the first six months of 2003 and $0.8 million in the first six months of 2002. In addition, gains of $2.0 million relating primarily to options bought and/or sold in the management of the Partnership's Enron position and mark-to-market changes in the offsetting purchased volumes that were booked in 2002.

Depreciation and Amortization. Depreciation and amortization expense was $5.0 million for the six months ended June 30, 2003 compared to $3.9 million for the six months ended June 30, 2002, an increase of $1.2 million, or 30%. This increase was primarily due to an increase in fixed assets of $37.6 million from June 30, 2002 to June 30, 2003 (excluding the acquisition of assets from DEFS which was completed on June 30, 2003, and therefore, had no affect on depreciation expense for the period).

Interest Expense. Interest expense was $0.9 million for the six months ended June 30, 2003 compared to $1.7 million for the six months ended June 30, 2002, a decrease of $0.8 million, or 48%. This decrease was due to a reduction in bank debt from the proceeds of the initial public offering.

Other Income (Expense). Other income (expense) includes costs associated with a lawsuit settlement of $0.1 million offset by income from affiliated partnerships.

Net Income (Loss). Net income (loss) for the six months ended June 30, 2003 was $5.8 million compared to ($28,000) for the six months ended June 30, 2002, an increase of $5.8 million. The principal reasons for this increase were an increase in gross margin of $8.7 million, offset principally by an increase in stock based compensation of $3.1 million.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Revenues. Midstream revenues were $437.7 million for the year ended December 31, 2002 compared to $362.7 million for the year ended December 31, 2001, an increase of $75.0 million, or 21%. Revenues were higher in 2002 than in 2001 due to the contribution of the Corpus Christi system, the Gregory gathering system and the Gregory processing plant, which generated $120.5 million in additional revenues in 2002, as these assets were not acquired until May 2001. This increase was partially offset by a decline in natural gas prices from an average NYMEX settlement price of $4.273 per MMBtu in 2001 to $3.221 per MMBtu in 2002, which reduced revenues by $44.0 million.

Treating revenues were $14.8 million for the year ended December 31, 2002 compared to $24.4 million in the same period in 2001, a decrease of $9.5 million, or 39%. The decline was due to the decrease in the price of natural gas, which accounted for $11.8 million of the decrease in treating revenues, a change in the contracts at certain plants to discontinue purchasing and reselling the treated gas and instead to receive only a treatment fee, which accounted for $4.8 million of the decrease, and a decrease in volume at one plant which accounted for $0.7 million of the decrease. This decline was partially offset by volume increases at two plants which generated an additional $5.6 million of revenue, 14 new plants placed in service in 2002 which collectively added $1.9 million, and the acquisition of the Rosita plant in May 2001, which generated an additional $0.3 million.

Purchased Gas Costs. Midstream purchased gas costs were $414.0 million for the year ended December 31, 2002 compared to $344.8 million for the year ended December 31, 2001, an increase of $69.2 million, or 20%. Costs increased by $113.7 million as the Corpus Christi system, the Gregory gathering system and the Gregory processing plant were purchased in May 2001 and only five months of their operating results were included in the 2001 period. This increase was partially offset by the decline in natural gas prices discussed above, which reduced costs by $44.0 million.

Treating purchased gas costs were $5.8 million in 2002 compared to $18.1 million in 2001, a decrease of $12.3 million or 68%. The decrease in natural gas prices caused $7.2 million of the decline, certain contracts were restructured from a purchase and resale of the associated gas to a pure treatment fee, causing a decline of $4.8 million, and a decrease in treating volumes at one plant caused $0.7 million of the decline. This decrease was partially offset by costs at a new facility which created additional purchased gas costs of $0.3 million.

Operating Expenses. Operating expenses were $10.5 million for the year ended December 31, 2002, compared to $7.4 million for the year ended December 31, 2001, an increase of $3.0 million, or 41%. The increase was primarily associated with the CCNG assets purchased in May 2001.

General and Administrative Expenses. General and administrative expenses were $8.5 million for the year ended December 31, 2002 compared to $5.9 million for the year ended December 31, 2001, an increase of $2.5 million, or 43%. The increases were associated with increases in staffing associated with the requirements of the CCNG assets and in preparation for our initial public offering.

Impairments. Impairment expense was $4.2 million in 2002 compared to $2.9 million in 2001. Intangible assets were booked associated with the contract values of certain treating plants and other assets in conjunction with the Yorktown investment in May 2000. Impairment charges in 2002 and 2001 are associated with writing off certain of these intangible contract values. The charges in 2001 relate to intangible contract values associated with the Jonesville processing plant, which was transferred out of

the partnership in conjunction with the initial public offering. Impairment charges in 2002 are primarily associated with intangible contract values at four specific treating plants.

(Profit) Loss on Energy Trading. The profit on energy trading was $2.7 million for the year ended December 31, 2002 compared to a loss of $3.7 million for the year ended December 31, 2001, an increase of $6.4 million. Included in these amounts are realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $1.8 million in 2002 and $1.9 million in 2001. In addition, gains of $0.9 million relating primarily to options bought and/or sold in the management of our Enron position and the offsetting mark-to-market purchased volumes were booked in 2002. Offsetting the gains from the producer services off-system gas marketing

operations in 2001 was the $5.7 million reserve booked against our Enron receivable. See "Year Ended December 31, 2001 Compared to Year Ended December 31, 2000—(Profit) Loss on Energy Trading" on page 57.

Depreciation and Amortization. Depreciation and amortization expense was $7.7 million for the year ended December 31, 2002 compared to $6.1 million for the year ended December 31, 2001, an increase of $1.6 million, or 27%. The increase is primarily related to additional depreciation expense associated with the CCNG assets purchased in May 2001, partially offset by a decrease in amortization expense due to goodwill no longer being amortized in 2002 in accordance with SFAS 142.

Interest Expense. Interest expense was $2.7 million for the year ended December 31, 2002 compared to $2.3 million for the year ended December 31, 2001, an increase of $0.5 million, or 21%. The increase relates primarily to bank debt incurred in the acquisitions of the CCNG assets in May, 2001, offset by lower interest rates.

Net Income (Loss). Net income (loss) for the year ended December 31, 2002 was $2.0 million compared to ($3.9) million for the year ended December 31, 2001, an increase of $5.9 million. Gross margin increased by $8.6 million from 2001 to 2002, offset by increases in ongoing cash costs for operating expenses, general and administrative expenses, and interest expense as discussed above. Non-cash charges for depreciation and amortization expense and impairment expense also increased, offset by the profit on energy trading contracts.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues. Midstream revenues were $362.7 million for the year ended December 31, 2001 compared to $91.6 million for the year ended December 31, 2000, an increase of $271.1 million, or 296%. Revenues were higher in 2001 primarily due to:

- ownership of the Arkoma system for the full year in 2001 as compared to only five months in 2000 contributed to an increase in revenues by $10.3 million;
- ownership of the Gulf Coast system for the full year in 2001 as compared to only four months in 2000 contributed to an increase in revenues by $68.4 million;
- the acquisition of the Corpus Christi system in May 2001 increased revenues by $117.0 million;
- the acquisition of the Gregory gathering system in May 2001 increased revenues by $52.5 million; and
- the acquisition of the Gregory processing plant in May 2001 increased revenues by $13.1 million. This was partially offset by the closure of the Jonesville plant, which contributed $4.0 million of revenues in 2000.

The remaining increase in Midstream revenue is primarily attributable to the average price of natural gas in 2001 being approximately $0.39 per MMBtu higher than the average price in 2000.

Revenues for natural gas treating were $24.4 million in 2001 compared to $23.3 million in 2000, an increase of $1.0 million, or 4%, due to new plants placed in service.

Purchased Gas Costs. Midstream division purchased gas costs for the year ended December 31, 2001 were $344.8 million compared to $86.4 million for the prior year, an increase of $258.3 million, or 299%. Costs were higher in 2001 primarily due to:

- ownership of the Arkoma system for the full year in 2001 as compared to only five months in 2000 contributed to an increase in costs by $9.0 million;
- ownership of the Gulf Coast system for the full year in 2001 as compared to only four months in 2000 increased costs by $65.3 million;
- the acquisition of the Corpus Christi system in May 2001 increased costs by $114.0 million;
- the acquisition of the Gregory gathering system in May 2001 increased costs by $49.9 million; and
- the acquisition of the Gregory processing plant in May 2001 increased costs by $9.9 million. This was partially offset by the shutdown of the Jonesville processing plant, which had $3.1 million of costs during 2000.

Treating division purchased gas costs were $18.1 million in 2001 compared to $19.6 million in 2000, a decrease of $1.5 million, or 8%. In combination with the improvement in revenues in natural gas treating, the decrease in costs resulted in an improvement in gross margin of $2.5 million, or 68%. This improvement was primarily attributable to new plants placed in service for a fee, as opposed to purchase and resale of the gas.

Operating Expenses. Operating expenses were $7.4 million for the year ended December 31, 2001, compared to $2.3 million for the year ended December 31, 2000, an increase of $5.1 million, or 218%. Expenses were higher in 2001 than in 2000 primarily due to:

- ownership of the Arkoma system for the full year in 2001 as compared to only five months in 2000 increased expenses by $0.6 million;
- ownership of the Gulf Coast system for the full year in 2001 as compared to four months in 2000 increased expenses by $1.0 million;
- the acquisition of the Corpus Christi system in May 2001 increased expenses by $0.9 million;
- the acquisition of the Gregory gathering system increased expenses by $0.5 million;
- the acquisition of the Gregory processing plant increased expenses by $1.3 million, and the shut down of the Jonesville plant in 2001 resulted in a decrease of $0.3 million; and
- operating expenses for the Treating division increased by $0.8 million due to 10 new operated plants being placed in service.

General and Administrative Expenses. General and administrative expenses were $5.9 million for the year ended December 31, 2001 compared to $2.8 million for the year ended December 31, 2000, an increase of $3.1 million, or 110%. The increase in general and administrative expenses were associated with the increase in employees caused by our rapid growth and preparation for our initial public offering. Total personnel employed increased from 44 to 107 between the end of 2000 and the end of 2001.

Stock-based Compensation. Stock-based compensation expense was zero in 2001 compared to $8.8 million for the year ended December 31, 2000. Stock based compensation in 2000 was associated with the valuation of management's interest in our predecessor as a result of the Yorktown investment in May 2000.

Impairments. Impairment expense was $2.9 million for the year ended December 31, 2001 compared to zero for the prior year. The impairment charge was recorded to reduce the carrying value of the Jonesville plant and related intangible assets to fair value in accordance with SFAS 121. See "—Critical Accounting Policies—Impairment of Long-Lived Assets" beginning on page 59.

(Profit) Loss on Energy Trading. The loss on energy trading for the year ended December 31, 2001 was $3.7 million compared to a profit of $1.9 million for the prior year. The loss on energy trading in 2001 included $5.7 million associated with the write-down of the estimated realizable value of our receivable from Enron North America Corp., a subsidiary of Enron Corp., at December 31, 2001. On December 2, 2001, Enron Corp. and certain subsidiaries, including Enron North America Corp., each filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code. Enron North America failed to make timely payment of approximately $3.9 million for physical delivery of gas in 2001. This amount remained outstanding as of December 31, 2001. Additionally, we had entered into natural gas hedging and physical delivery contracts with Enron North America. According to the terms of the contracts, Enron North America is liable to us for the mark-to-market value of all contracts outstanding on the date we exercised our termination right under the contracts, which totaled approximately $4.6 million and which has been recorded as a receivable from Enron North America. We have accounted for these contracts as energy trading contracts whereby changes in fair value of the fixed price purchase commitments are recognized in earnings.

We had offsets to the above amounts totaling approximately $0.3 million, resulting in a net $8.2 million receivable from Enron North America at December 31, 2001. Due to the uncertainty of future collections, a charge and related allowance for 70% of the net receivable, or $5.7 million, was recorded at December 31, 2001. Further adjustments to the Enron receivable will be recognized in earnings when management believes recovery of the asset is assured or additional reserves are warranted.

The receivable from Enron was not contributed to us.

Partially offsetting the Enron-related loss in the 2001 period were the realized margins on delivered volumes in the producer services "off-system" gas marketing operations. In 2001, the realized margins from the producer services operations were approximately $1.9 million, compared to approximately $1.8 million in 2000.

Depreciation and Amortization. Depreciation and amortization expense was $6.1 million for the year ended December 31, 2001 compared to $2.8 million for the year ended December 31, 2000, an increase of $3.3 million, or 119%. The increase in depreciation and amortization is primarily related to acquisitions of new assets, which resulted in additional depreciation and amortization expense as follows:

- ownership of the Arkoma system for the full year in 2001 as compared to only five months in 2000 increased depreciation and amortization expense by $0.5 million;
- ownership of the Gulf Coast system for the full year in 2001 as compared to four months in 2000 increased depreciation and amortization expense by $0.6 million; and
- the acquisition of the CCNG assets in May 2001 increased depreciation and amortization expense by $1.3 million.

In addition, the accounting associated with the Yorktown investment in May 2000 resulted in an increase in depreciation and amortization for subsequent periods. Therefore, depreciation and amortization expense for the first four months of 2000 is approximately $0.4 million lower than if the investment had occurred at the beginning of 2000.

Interest Expense. Interest expense was $2.3 million for the year ended December 31, 2001 compared to $0.6 million for the year ended December 31, 2000, an increase of $1.6 million, or 270%. The increase was principally caused by increases in average outstanding borrowings as a result of the CCNG acquisition and the acquisition and refurbishment of treating plants. In addition, borrowings relative to the Arkoma and Gulf Coast assets were outstanding for the full year in 2001 as compared to only a part of 2000.

Net Income (Loss). Net loss for the year ended December 31, 2001 was ($3.9) million compared to ($6.1) million for the year ended December 31, 2000. Gross margin improved from $8.9 million in 2000 to $24.2 million in 2001, an improvement of $15.3 million, or 171%, largely as a result of acquisition-related growth as discussed above. This improvement was partially offset by increases in recurring cash charges for operating expenses, general and administrative expenses, and interest expense totaling $9.8 million, non-cash charges for depreciation and amortization of $3.3 million, and the loss on energy trading contracts and impairments totaling $8.5 million.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. Our critical accounting policies are discussed below. For further details on our accounting policies and a discussion of new accounting pronouncements, see Note 2 of the Notes to Combined Financial Statements.

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

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

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

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

We conduct "off-system" gas marketing operations as a service to producers on systems that we do not own. We refer to these activities as part of producer services. In some cases, we earn an agency fee from the producer for arranging the marketing of the producer's natural gas. In other cases, we purchase the natural gas from the producer and enter into a sales contract with another party to sell the natural gas. These are reflected at net amounts in the profit (loss) on energy trading contracts line

on the statement of operations. Where we take title to the natural gas, the purchase contract is recorded as cost of gas purchased and the sales contract is recorded as revenue upon delivery.

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

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period is reported as profit or loss on energy trading in the statement of operations.

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

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;
- the availability and prices of natural gas supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas exploration and production activities will not occur or be successful;
- our dependence on certain significant customers, producers, and transporters of natural gas; and
- competition from other midstream companies, including major energy producers.

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

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $15.1 million and $27.1 million for the six months ended June 30, 2003 and 2002, respectively. Net cash provided by operating activities in 2003 declined principally due to fund flows for working capital accounts ($20.0 million) partially offset by higher margins ($8.7 million).

Net cash provided by (used in) operating activities was $20.0 million, ($8.3) million and $15.1 million for the years ended December 31, 2002, 2001 and 2000, respectively. Net cash provided by operating activities in 2002 improved principally due to higher margins ($8.6 million) offset by higher cash expenses ($5.6 million), the loss of energy contracts related to Enron in 2001 ($5.7 million) and fund flows for working capital accounts. Net cash used in operating activities during the year ended December 31, 2001 was $23.4 million lower than the prior year principally attributable to higher margins ($15.3 million), offset by higher cash expenses ($9.8 million), the loss on energy trading contracts related to Enron ($5.7 million), and fund flows for working capital accounts.

Net cash used in investing activities was $85.2 million and $10.3 million for the six months ended June 30, 2003 and 2002, respectively. Net cash used in investing activities during 2003 related to the DEFS acquisition as well as internal growth projects and investing activities during 2002 primarily related to internal growth projects. The internal growth projects referred to for both six month periods were buying, refurbishing and installing treating plants, and other internal growth capital projects, including the Gregory plant expansion in 2003.

Net cash used in investing activities was $33.2 million, $52.5 million and $28.5 million for the years ended December 31, 2002, 2001 and 2000, respectively. Net cash used in investing activities during all periods was primarily related to acquisition and internal growth projects. Net cash used in investing activities during each of the years ended December 31, 2002 and 2001 was primarily to fund acquisitions of the Vanderbilt system, the CCNG assets, buying and refurbishing and installing treating plants, the Arkoma and Gulf Coast systems, our acquisition of Millennium Gas Services, Inc., and internal growth capital projects.

Net cash provided by (used in) financing activities was $70.4 million and ($2.7) million for the six months ended June 30, 2003 and 2002, respectively. Financing activities in 2003 relate principally to the funding of the DEFS acquisition. Financing activities during 2002 primarily represented funding or refunding of our debt and working capital needs.

Net cash provided by financing activities was $14.2 million, $42.6 million and $36.8 million for the years ended December 31, 2002, 2001 and 2000, respectively. Financing activities primarily represent net borrowings from banks to fund our acquisitions, other investments discussed above, and working capital needs, proceeds from our initial public offering in 2002 and capital contributions to our predecessor.

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

- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain existing operating capacity of our assets and to extend their useful lives, or other capital expenditures which do not increase the partnership's cash flows; and

- growth capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity, processing plants or treating plants, and to construct or acquire new pipelines, processing plants or treating plants.

Given our objective of growth through acquisitions, we anticipate that we will continue to invest significant amounts of capital to grow and acquire assets. We are nearing completion of an expansion of our Gregory processing plant. The expansion will increase the capacity of the plant from approximately 90,000 Mcf/d to 150,000 Mcf/d and will cost approximately $8.0 million. For fiscal 2003, maintenance capital expenditures are expected to be between $4.0 to $5.0 million.

We believe that cash generated from operations will be sufficient to meet our minimum quarterly distributions and anticipated maintenance capital expenditures through December 31, 2003. We expect to fund our growth capital expenditures from cash provided by operations and, to the extent necessary, from the proceeds of borrowings under the bank credit facility and senior secured notes discussed below and the issuance of additional common units. We may not be able to issue additional units or may not be able to issue such units on favorable terms primarily as a result of market conditions for our securities. Our ability to pay distributions to our unitholders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2002, is as follows:

	Payments due by period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
			(in millions)		
Long-Term Debt	$ 22.5	$ —	$ 11.0	$ 11.5	—
Capital Lease Obligations	—	—	—	—	—
Operating Leases	2.2	0.8	1.4	—	—
Unconditional Purchase Obligations	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—
Total Contractual Obligations	$ 24.7	$ 0.8	$ 12.4	$ 11.5	—

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

Payments due on total debt outstanding at June 30, 2003 are as follows (in millions):

Less than 1 year	$ 0.1
1-3 years	77.5
3-5 years	14.1
More than 5 years	7.1
Total	$ 98.8

Thereafter upon the closing of the offering, the proceeds of the offering will be used to retire a portion of the bank debt scheduled above.

Description of Indebtedness

Upon completion of this offering, we expect our total outstanding long-term indebtedness to be approximately $47.5 million, including approximately $40.0 million of senior secured notes, $6.8 million under our bank credit facility, and approximately $0.7 million of other indebtedness.

Bank Credit Facility. In June 2003, our operating partnership, Crosstex Energy Services, L.P., entered into a $100 million senior secured credit facility with Union Bank of California, N.A. (as a lender and as administrative agent) and other lenders, consisting of the following two facilities:

- a $70.0 million senior secured revolving acquisition facility; and
- a $30.0 million senior secured revolving working capital and letter of credit facility.

The acquisition facility was used for the DEFS acquisition and will be used to finance the acquisition and development of gas gathering, treating and processing facilities, as well as general partnership purposes. After giving effect to this offering, we expect our operating partnership to have approximately $63.2 million of the acquisition facility available for future borrowings. The acquisition facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the acquisition credit facility may be reborrowed.

The working capital and letter of credit facility will be used for ongoing working capital needs, letters of credit, distributions to partners and general partnership purposes, including future acquisitions and expansions. We currently have $24.0 million of letters of credit issued under the working capital and letter of credit facility at the closing of the offering, leaving approximately $6.0 million available for future issuances of letters of credit and/or cash borrowings. The aggregate amount of borrowings under the working capital and letter of credit facility is subject to a borrowing base requirement relating to the amount of our cash and eligible receivables (as defined in the credit agreement), and there is a $10.0 million sublimit for cash borrowings. This facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the working capital and letter of credit facility may be reborrowed. We will be required to reduce all working capital borrowings to zero for a period of at least 15 consecutive days once each year.

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

Indebtedness under the acquisition facility and the working capital and letter of credit facility bear interest at our operating partnership's option at the administrative agent's reference rate plus 0.25% to 1.50% or LIBOR plus 1.75% to 3.00%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.50% to 2.00% per annum, plus a fronting fee of 0.125% per annum. If the bank credit facility had been in place for the six months ended June 30, 2003, our operating partnership's weighted-average interest rate would have been 4.61%. Our operating partnership will incur quarterly commitment fees based on the unused amount of the credit facilities.

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

- incur indebtedness;

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

The bank credit facility also contains covenants requiring us to maintain:

- a maximum ratio of total funded debt to consolidated EBITDA (each as defined in the bank credit facility), measured quarterly on a rolling four-quarter basis, of 3.75 to 1 through March 31, 2004, declining to 3.5 to 1 beginning June 30, 2004, pro forma for any asset acquisitions;
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis, equal to 3.50 to 1;
- minimum current ratio (as defined in the credit agreement), measured quarterly, of 1 to 1; and
- a minimum tangible net worth (as defined in the credit agreement) of $60.0 million, plus one-half of certain equity contribution proceeds received after December 31, 2002.

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

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

Senior Secured Notes. In June 2003, our operating partnership entered into a master shelf agreement with an institutional lender pursuant to which it issued $30.0 million aggregate principal amount of senior secured notes with an interest rate of 6.95% and a maturity of seven years. In July 2003, our operating 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.

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

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

assets and a pledge of all of our equity interests in certain of our subsidiaries. The senior secured notes are guaranteed by our operating partnership's subsidiaries and us.

The senior secured notes are redeemable, at our operating 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 master shelf agreement relating to the notes contains substantially the same covenants and events of default as the bank credit facility.

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

As of June 30, 2003, due to the timing of the financing associated with the acquisition of assets from DEFS, our operating partnership was not in compliance with the current ratio restrictions under the bank credit facility and the master shelf agreement governing the senior secured notes. In August 2003, our operating partnership obtained waivers of this restriction from the bank credit facility and the senior secured note participants. Our operating partnership was in compliance with all debt covenants at December 31, 2002, and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement in June 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. This agreement appointed Union Bank of California, N.A. to act as collateral agent and authorized Union Bank to execute various security documents on behalf of the lenders under the bank credit facility and the initial purchases of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing 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, 2000, 2001 or 2002 or the six months ended June 30, 2003. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us, see "Business—Environmental Matters" beginning on page 81.

Recent Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement establishes standards for accounting for obligations associated with the retirement of tangible long-lived assets. This standard was required to be adopted by us beginning on January 1, 2003. We do not presently have any significant asset retirement obligations, and accordingly, the adoption of SFAS No. 143 did not have a significant impact on our financial position and results of operations.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred rather than when the entity commits to an exit plan. This standard is effective for all exit or disposal activities which are initiated after December 31, 2002. The adoption of SFAS No. 146 did not have any impact on our financial position or results of operations.

In January 2003, the FASB issued Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Others*. FIN No. 45 requires an entity to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. Certain guarantees are excluded from the measurement and disclosure provisions while certain other guarantees are excluded from the measurement provisions of the interpretation. The measurement provisions of this statement apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure provisions apply to financial statements for periods ending after December 15, 2002. The adoption of the statement is not expected to have a material effect on the Partnership's financial statements when adopted.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*. FIN No. 46 requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception for any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this interpretation must be applied at the beginning of the first interim or annual period beginning after June 15, 2003. The Partnership is not the primary beneficiary of any significant variable interest entities.

On May 15, 2003, the Financial Accounting Standards Board issued Statement No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity.* The statement requires issuers to classify as liabilities (or assets in some circumstance) three classes of freestanding financial instruments that embody obligations for the issuer. Generally, the statement is effective for financial instruments entered into or modified after May 31, 2003 and is otherwise effective at the beginning of the first interim period beginning after June 15, 2003. The adoption of this pronouncement will not have an impact on our financial statements.

Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity price variations, primarily due to fluctuations in the price of a portion of the natural gas we sell, and for the portion of the natural gas we process and for which we have taken the processing risk, we are at risk for the difference in the value of the NGL products we produce versus the value of the gas used in fuel and shrinkage in their production. We also incur credit risks and risks related to interest rate variations.

Commodity Price Risk. For the six months ended June 30, 2003, approximately 8.1% of the natural gas we market was purchased at a percentage of the relevant natural gas index price, as

opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our sale margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. In addition, of the gas we process at our Gregory processing plant, we were exposed to the processing risk on 22% of the gas we purchased during the six months ended June 30, 2003. As a result, our processing margins on this portion of the gas will be higher during periods when the price of gas is low relative to the value of the liquids produced and our margins will be lower during periods when the value of gas is high relative to the value of liquids. For the six months ended June 30, 2003, a $0.01 per gallon change in NGL prices offset by a change of $0.10 per MMBtu in the price of natural gas would have changed our processing margin by $109,051. Changes in natural gas prices indirectly may impact our profitability since prices can influence drilling activity and well operations and thus the volume of gas we can gather, transport, process and treat.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a Risk Management Committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our Risk Management Committee. Hedges to protect our processing margins are generally for a more limited time frame than is possible for hedges in natural gas, as the financial markets for NGLs are not as developed as the markets for natural gas. Such hedges generally involve taking a short position with regard to the relevant liquids and an offsetting short position in the required volume of natural gas.

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

We manage our price risk related to future physical purchase or sale commitments for our producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas prices. However, we are subject to counterparty risk for both the physical and financial contracts. We account for certain of our producer services natural gas marketing activities as energy trading contracts or derivatives.

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

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

Interest Rate Risk. We will be exposed to changes in interest rates, primarily as a result of our anticipated long-term debt with floating interest rates. We expect to have $47.5 million of long-term indebtedness outstanding at the closing of this offering. We may make use of interest rate swap agreements to adjust the ratio of fixed and floating rates in the debt portfolio, although no such agreements are currently in place. The impact of a 100 basis point increase in interest rates on our expected debt would have a minimal impact on our interest expense and income before taxes, as a substantial portion of our debt is at fixed interest rates.

BUSINESS

Overview

We are a rapidly growing independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas. We connect the wells of natural gas producers in our market areas to our gathering systems, treat natural gas to remove impurities to ensure that it meets pipeline quality specifications, process natural gas for the removal of natural gas liquids or NGLs, transport natural gas and ultimately provide an aggregated supply of natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipelines and thereby generate gross margins based on the difference between the purchase and resale prices. In addition, we purchase natural gas from producers not connected to our gathering system for resale and sell natural gas on behalf of producers for a fee.

Our major assets include over 2,500 miles of natural gas gathering and transmission pipelines, three natural gas processing plants connected to our gathering systems with a total NGL production capacity of 289,800 gallons per day and 53 natural gas treating plants. Our gathering systems consist of a network of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third-party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. Our processing plants remove NGLs from a natural gas stream and fractionates, or separates, the NGLs into separate NGL products, including ethane, propane, mixed butanes and natural gasoline. Our natural gas treating plants, located largely in the Texas Gulf Coast area, remove impurities from natural gas prior to delivering the gas into pipelines to ensure that it meets pipeline quality specifications.

Set forth in the table below is a list of our acquisitions since January 2000.

Acquisition	Acquisition Date	Purchase Price	Asset Type	Average Throughput at Time of Acquisition (MMBtu/d)	Average Throughput for Six Months Ended June 30, 2003 (MMBtu/d)
		(in thousands)			
Provident City Plant	February 2000	$ 350	Treating plants	2,200	22,774
Will-O-Mills (50%)	February 2000	2,000	Treating plants	11,700	16,521
Arkoma Gathering System	September 2000	10,500	Gathering pipeline	12,000	10,670
Gulf Coast System	September 2000	10,632	Gathering and transmission pipeline	117,000	85,052
CCNG Acquisition	May 2001	30,003	Gathering and transmission pipeline and processing plant	272,000	402,323
Pettus Gathering System	June 2001	450	Gathering system	—	—
Millennium Gas Services	October 2001	2,124	Treating assets	—	—
Hallmark Lateral	June 2002	2,300	Pipeline segment	—	46,020
Pandale System	June 2002	2,156	Gathering pipeline	16,000	12,737
KCS McCaskill Pipeline	June 2002	250	Pipeline segment	—	—
Vanderbilt System	December 2002	12,000	Transmission pipeline	32,000	40,850
Will-O-Mills (50%)	December 2002	2,200	Treating plant	9,700	16,521
DEFS Acquisition (includes 12.4% of Seminole gas processing plant)	June 2003	67,300	Gathering and transmission systems, processing plants and pipeline systems	154,000	

We have two operating divisions, the Midstream division, which consists of our natural gas gathering, transmission, processing, marketing and producer services operations, and the Treating division, which provides natural gas treating for the removal of carbon dioxide and other contaminants.

For the year ended December 31, 2002, revenues for our Midstream division and Treating division were $437.7 million and $14.8 million, respectively. For the six months ended June 30, 2003, revenues for our Midstream division and Treating division were $469.3 million and $10.5 million, respectively.

Midstream Division. Our primary Midstream assets include systems located primarily along the Texas Gulf Coast and in south-central Mississippi, which, in the aggregate, consist of approximately 2,500 miles of gathering and transmission pipelines and three natural gas processing plants. After giving pro forma effect our recent acquisition of assets from DEFS, for the year ended December 31, 2002 and the six months ended June 30, 2003, we would have gathered and transported approximately 501,233 MMBtu/d and 603,160 MMBtu/d of natural gas, respectively.

In our producer services operations, we purchase for resale volumes of natural gas that do not move through our gathering, processing or transmission assets from over 50 independent producers. We focus on supply aggregation transactions in which we either purchase and resell gas and thereby eliminate the need of the producer to engage in the marketing activities typically handled by in-house marketing or supply departments of larger companies, or act as agent for the producer. In a recent survey by Mastio & Co., we were ranked first in satisfaction among producers. According to the survey, producers rated buyers on 25 attributes, including creditworthiness, promptness of payment, willingness to solve problems, accessibility, responsiveness, experience and price competitiveness.

Treating Division. As of June 30, 2003, we owned 55 mobile, skid-mounted treating plants of various sizes, 32 of which were operated by our personnel, 10 of which were operated by producers, 13 of which were held in inventory. The treating plants remove carbon dioxide and hydrogen sulfide from natural gas before it is delivered into transportation systems to ensure that it meets pipeline quality specifications.

Competitive Strengths

We believe that we are well positioned to compete in the natural gas gathering, transmission, treating, processing and producer services businesses. Our competitive strengths include:

- *Strategic position in the Texas Gulf Coast and Mississippi.* Our Gregory and Conroe processing plants and 59% of our total gathering and transmission pipeline miles are located in the Texas Gulf Coast. The Texas Gulf Coast is characterized by consistently high levels of drilling activity, which provide us with significant opportunities to access newly developed gas supplies. Our Gregory processing plant and its associated gathering system are strategically located in the liquids-rich Corpus Christi Bay and Mustang Island area. This area is currently undergoing significant exploration activity, and we believe that most of the producers drilling in the area will choose to process and market their gas through our systems due to the lack of other economic alternatives. Our Texas Gulf Coast systems also have access to a variety of industrial and utility end-user markets, as well as to other interstate and intrastate pipeline systems. Many industrial consumers locate in this region because of its proximity to large quantities of natural gas. We believe our significant presence and asset base in the Texas Gulf Coast generally provides us with a competitive advantage in capturing new supplies of natural gas and markets for natural gas because of our resulting lower costs of handling newly connected gas and delivering it to market. The acquisition of the AIM pipeline system, located in south-central Mississippi, allowed us to establish a new core area outside of our strategic position in the Texas Gulf Coast. We believe we can use our proven expertise in expanding and developing acquired assets to develop and expand the AIM pipeline system through aggressive marketing, new construction and cross-selling our treating services.

- *Asset base with available capacity.* By aggressively marketing directly to producers and end users and adding connections to new customers, we believe we have the opportunity to leverage our existing asset base in order to more fully utilize the capacity of our systems and thereby

significantly increase throughput and cash flows. Since our pipelines and gathering systems have unused capacity, transporting additional volumes of natural gas through our systems should provide incremental operating income. Our Gulf Coast system, Vanderbilt system, Corpus Christi system, Gregory gathering system, Arkoma system and AIM pipeline system are operating at 40.4%, 27.9%, 59.2%, 64.9%, 49.9% and 40.0% of capacity, respectively, based on average daily throughput for the six months ended June 30, 2003. We believe our inventory of 13 treating plants gives us a competitive advantage for capturing new treating business since we can often have a plant in service quicker than our competitors.

- *Range of services.* We offer a full range of midstream services to natural gas producers, including gathering, transmission, treating, processing and marketing. In addition, as a component of our producer services business, we purchase natural gas for sale to others and in doing so provide risk management opportunities to natural gas producers. We believe this full range of services gives us advantages in competing for new business because we can provide substantially all the services a producer requires to get its production of natural gas to market as compared to our competitors who often do not provide a full range of services. For example, providing treating services allows us to establish new relationships with producers and facilitates the sale of additional services to producers. In addition, we provide a full range of services to natural gas buyers including an aggregated supply of natural gas, load balancing and price risk management, which allows buyers to find a significant volume of natural gas that meets their requirements without having to negotiate with multiple producers.

- *Proven acquisition and development expertise.* Since January 2000, we have acquired and integrated 13 operations with an aggregate purchase price of approximately $142.3 million, including our recent $67.3 million acquisition of assets from DEFS which enabled us to expand our operations into Mississippi and Alabama. Our management team's significant industry contacts have enabled us to become aware of, and gain access to, strategic acquisition opportunities. We intend to use our experience and reputation in strategically acquiring assets to continue to grow through accretive acquisitions, focusing on opportunities in which we see potential to improve throughput volumes and cash flows through marketing and new construction and expansion projects. We have invested in excess of $50.0 million in our construction and expansion projects from January 2000 through June 2003.

- *Flexible financial structure.* Our operating partnership has a $70.0 million acquisition facility, approximately $63.2 million of which will be available upon the closing of this offering, and a $30.0 million working capital and letter of credit facility. In addition, our operating partnership has a $50.0 million master shelf facility for senior secured notes. Our operating partnership has issued $40.0 million of senior secured notes under this facility, and any future issuances will be subject to negotiation of certain terms, including pricing. We believe the available capacity under the bank credit facility and the senior secured notes, combined with our ability to access the capital markets, should provide us with a flexible financial structure that will facilitate our expansion and acquisition strategy.

- *Experienced and motivated management.* Our management team's extensive experience and contacts within the midstream industry provides a strong foundation for managing and enhancing our operations, for accessing strategic acquisition opportunities and for constructing new assets. Our senior management team, which indirectly owns approximately 49,000 common and 686,000 subordinated units and approximately 15% of our general partner, has an average of over 20 years of industry experience primarily with the type of assets and the markets in which we currently operate. Our management team also has substantial experience selling gas in a variety of interstate and intrastate markets. Please read "Management—Directors and Executive Officers of Crosstex Energy GP, LLC" beginning on page 86 for a discussion of the experience of our executive officers.

Business Strategy

Our strategy is to increase distributable cash flow per unit by making accretive acquisitions of assets that are essential to the production, transportation and marketing of natural gas, improving the profitability of our owned assets by increasing their utilization while controlling costs and pursuing new construction or expansion in core operating areas. Our strategy is based on our expectation of a continued high level of drilling in our principal geographic areas and a process of ongoing divestitures of gas processing and transportation assets by large industry participants. We believe these two factors should present opportunities for continued expansion in our existing areas of operation as well as opportunities to acquire assets in new geographic areas that may serve as a platform for future growth. Key elements of our strategy include the following:

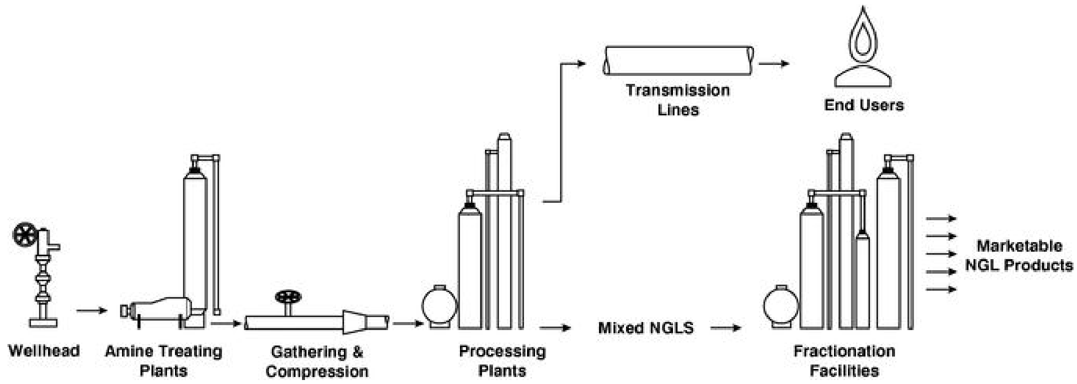
- *Pursuing accretive acquisitions.* We intend to use our substantial acquisition and integration experience to continue to make strategic acquisitions of midstream assets that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of the acquired asset. We pursue acquisitions that we believe will add to existing core areas in order to capitalize on our existing infrastructure, personnel, and producer and consumer relationships. We also examine opportunities to establish new core areas in regions with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas. We plan to establish new core areas primarily through the acquisition of key assets that will serve as a platform for further growth both through additional acquisitions and the construction of new assets. A recent example of establishing a new core area includes the AIM pipeline system acquired as part of the DEFS acquisition. This system provides us with a platform to develop a significant presence in the south-central Mississippi area.

- *Improving existing system profitability.* After we acquire or construct a new system, we begin an aggressive effort to market directly to both producers and end users in order to connect new supplies of natural gas, increase volumes and more fully utilize the system's capacity. Many of our recently acquired systems have excess capacity that provides us opportunities to increase throughput with minimal incremental cost. As part of this process, we focus on providing a full range of services to small and medium size independent producers and end users, including supply aggregation, transportation and hedging, which we believe provides us with a competitive advantage when we compete for sources of natural gas supply. Additionally, we emphasize increasing the percentage of our natural gas sales directly to end users, such as industrial and utility consumers in an effort to increase our operating margins. For the six months ended June 30, 2003, approximately 56% of our on-system natural gas sales were to industrial end users and utilities.

- *Undertaking construction and expansion opportunities.* We leverage our existing infrastructure and producer and customer relationships by constructing and expanding systems to meet new or increased demand for our gathering, transmission, treating, processing and marketing services. These projects include expansion of existing systems and construction of new facilities. As an example, we modified the Gregory system by adding a by-pass around our Gregory processing plant which allowed us to deliver an additional 30,000 Mcf/d of gas to the plant tailgate without processing. Our acquisition from Florida Gas Transmission established connections between our Corpus Christi and our Gulf Coast systems which increases our flexibility in balancing gas supply and market requirements throughout the regions covered. We are nearing completion of an expansion to increase the capacity of our Gregory processing plant to 150,000 Mcf/d, a 67.0% increase over its previous capacity. Upon completion of the expansion, we will begin marketing the additional gas through our Corpus Christi and Gulf Coast systems.

Industry Overview

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



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

Natural gas gathering. The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

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

Natural gas processing and fractionation. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of NGLs and contaminants, such as water, sulfur compounds, nitrogen or helium. Most natural gas produced by a well is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems is composed almost entirely of methane and ethane, with moisture and other contaminants removed to very low concentrations. Natural gas is processed not only to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas, but also to separate from the gas those hydrocarbon liquids that have higher value as NGLs. The removal and separation of individual hydrocarbons by processing is possible because of differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline quality natural gas and a mixed NGL stream, as well as the removal of contaminants. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline.

Natural gas transmission. Natural gas transmission pipelines receive natural gas from mainline transmission pipelines, plant tailgates, and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

Operations

Substantially all of our margins are derived from the value we add by gathering and transporting natural gas, treating natural gas, processing natural gas, purchasing natural gas for resale and marketing natural gas. Our natural gas gathering, transmission, processing, marketing and producer services operations are conducted by our Midstream division, and our treating operations are conducted by our Treating division.

Midstream Division

Our natural gas gathering and transmission operations include over 2,500 miles of pipeline and three processing plants. After giving pro forma effect to our recent acquisition of assets from DEFS, for the year ended December 31, 2002 and the six months ended June 30, 2003, we would have gathered and transported approximately 501,233 MMBtu/d and 603,160 MMBtu/d of natural gas, respectively.

Gulf Coast System. The Gulf Coast system is an intrastate pipeline system consisting of approximately 484 miles of gathering and transmission pipelines with a mainline from Refugio County in south Texas running northeast along the Gulf Coast to the Brazos River in Fort Bend County near Houston. Our gathering and transmission pipeline ranges in diameter from four to 20 inches. We acquired the Gulf Coast system in September 2000 for a purchase price of approximately $10.6 million.

The Gulf Coast system has two supply pipeline laterals which connect to gathering systems which collect natural gas from approximately 76 receipt points and five treating and processing plants operated by third parties. This system has three delivery laterals—an eight inch lateral into the Victoria area and a 16 inch lateral into the Bay City area—which deliver natural gas directly to large industrial and utility consumers along the Gulf Coast. The system interconnects with multiple third-party pipelines through which we may purchase volumes not gathered through our systems for resale or through which we might deliver natural gas to customers which are not connected to our system. We also hold firm transportation capacity on the TXU Lone Star pipeline, which provides access for our Gulf Coast mainline system in Fort Bend County to the Katy hub, a major natural gas physical exchange that allows access to seven third-party pipelines, including Kinder Morgan, TECO and Trunkline. The Gulf Coast system has a capacity of 200,000 Mcf/d and average throughput on this system was approximately 85,052 MMBtu/d for the six months ended June 30, 2003.

We generate operating profits in our Gulf Coast system through the margins we earn by purchasing, gathering, transporting and reselling natural gas. We purchase natural gas from a producer, pipeline or marketing company and then transport and resell the gas. As of June 30, 2003, we were purchasing gas from over 65 producers primarily pursuant to month-to-month contracts and were reselling the natural gas to approximately 10 customers primarily pursuant to short-term or month-to-month arrangements. For the six months ended June 30, 2003, approximately 93% of the natural gas volumes we purchased were purchased at a fixed price relative to an index and the remainder were purchased at a percentage of an index, and all the natural gas volumes we sold were sold at a fixed price relative to an index.

Vanderbilt System. Our Vanderbilt system consists of approximately 200 miles of gathering and transmission pipelines located in Wharton and Fort Bend Counties near our Gulf Coast system. Natural gas is supplied to the system from approximately 24 receipt points. The gas had been sold to the Exxon Katy plant and in June 2003 we reversed the flow of gas and began deliveries to the Formosa Hydrocarbons processing plant at Point Comfort, Texas. Our Vanderbilt system has a capacity of

130,000 Mcf/d and average throughput was approximately 40,850 MMBtu/d for the six months ended June 30, 2003. We acquired the Vanderbilt system in December 2002 for a purchase price of $12.0 million.

All the gas in the Vanderbilt system is now sold to Formosa Hydrocarbons under a ten year agreement which began in June 2003 to supply up to 60,000 Mcf/d. The gas is sold to Formosa at a fixed price relative to an index. Gas is purchased from approximately 10 producers, primarily pursuant to month-to-month arrangements, at approximately 24 receipt points. Approximately 61% percent of the gas is purchased at a percentage of an index, and the remainder is purchased at a fixed price relative to an index. We generate operating profits in the system through the margins we earn by purchasing gas from producers, then gathering, transporting and reselling the natural gas to Formosa.

Corpus Christi System. The Corpus Christi system is an intrastate pipeline system consisting of approximately 295 miles of gathering and transmission pipelines and extending from supply points in south Texas to markets in Corpus Christi, Texas. Our gathering and transmission pipelines range in diameter from four to 20 inches. We acquired the Corpus Christi system in May 2001 in conjunction with the acquisition of the Gregory gathering system and Gregory processing plant, which we collectively refer to as the CCNG Acquisition, for an aggregate purchase price of approximately $30 million. Based on the differences in how we operate and the prior owner operated the CCNG assets, the CCNG acquisition is not treated as an acquisition of a continuing business operation, but rather is accounted for as a purchase of assets. Prior to our acquisition, the CCNG assets were not treated as separate assets but part of a larger enterprise and very few transactions allocated to the CCNG systems were done on an arms-length basis with third parties and, accordingly, did not reflect market values. Since our acquisition, we have operated the assets as separate profit centers, with substantially all transactions done on an arms-length basis. After the completion of the acquisition, we hired 16 former employees of the seller, all of whom are in operational positions. Our Corpus Christi system had average throughput of approximately 152,000 MMBtu of gas per day at the time of our acquisition. The main lines comprising the Corpus Christi system were constructed in the 1940's with additional expansions throughout the 1990's. We believe the expected remaining life of the pipeline system is approximately 50 years.

Natural gas is supplied to the Corpus Christi system from approximately 13 receipt points, 14 treating and processing plants and third-party gathering systems and pipelines. The system interconnects with multiple third-party pipelines through which we purchase volumes not gathered through our systems for resale and deliver natural gas to customers which are not connected to our system, including the Banquette hub. The Corpus Christi system has a capacity of 350,000 Mcf/d and average throughput on this system was approximately 164,624 MMBtu/d for the six months ended June 30, 2003.

We generate operating profits in our Corpus Christi system through the margins we earn by purchasing, gathering, transporting and reselling natural gas. As of June 30, 2003, we were purchasing natural gas from approximately 27 producers generally on month-to-month or short-term arrangements. For the six months ended June 30, 2003, substantially all of the natural gas volumes we purchased were purchased at a fixed price relative to an index.

The Corpus Christi system transports natural gas to the Corpus Christi area where its customers include multiple major refineries and other industrial installations, as well as the local electric utility. As of June 30, 2003, we were selling gas to over 13 customers primarily pursuant to contracts that expire at various times between 2003 and 2006. For the six months ended June 30, 2003, all of the natural gas volumes we sold were sold at a fixed price relative to an index. New customers added since the acquisition of this system have increased our sales volumes by 50,000 Mcf/d, replacing less profitable sales volumes that have been discontinued. Additionally, we have a 15 year agreement to provide transportation services to Calpine Energy Services, LP, the owner of a co-generation facility in

Corpus Christi that came online in the fourth quarter of 2002. Under the agreement, we receive minimum annual payments in exchange for providing firm capacity of up to 100,000 MMBtu/d. This 500 megawatt co-generation facility receives gas solely through two interconnections to the Corpus Christi transmission system. During the six month period ended June 30, 2003, we transported approximately 49,000 MMBtu/d to the Calpine facility.

In June 2002, we acquired from Florida Gas Transmission approximately 70 miles of 20 inch transmission line, which we refer to as the Hallmark Lateral. We constructed an addition to this transmission line to connect our Gulf Coast and Corpus Christi systems. This connection allows us to transport gas between our two systems, reducing our dependence on third-party suppliers, move gas supplies to more favorable markets and enhance our margins. In November 2002, we completed construction of the interconnect between the Hallmark Lateral and the Florida Gas Transmission mainline. With this connection, we began selling gas into the Florida markets and we sold approximately 45,251 Mcf/d into Florida for the six months ended June 30, 2003.

Gregory Gathering System. We acquired the Gregory processing plant and the Gregory gathering system in May 2001 in connection with the acquisition of the Corpus Christi system. The plant and the gathering system are located north of Corpus Christi, Texas. The gathering system is connected to approximately 70 receipt points in San Patricio County, the Corpus Christi Bay area, Mustang Island, and adjacent coastal areas. The gathering system consists of approximately 297 miles of pipeline ranging in diameter from two inches to 18 inches with a total estimated throughput capacity of 200,000 Mcf/d. Until recently, all of the gas from the gathering system had been delivered to the inlet of the processing plant. Accordingly, the capacity of the gathering system was constrained by the inlet capacity of the plant, which is approximately 90,000 Mcf/d. We have modified the system to put a by-pass around the plant so that approximately 30,000 Mcf/d of gas can be delivered to the plant tailgate without processing in addition to volumes processed in the plant. The gathering system had average throughput of approximately 144,045 MMBtu/d for the six months ended June 30, 2003. Our Gregory gathering system had average throughput of approximately 76,500 MMBtu/d of gas per day at the time of our acquisition. The Gregory gathering system was constructed in the 1980s and we believe the expected remaining life of the pipeline system is approximately 50 years.

We generate operating profits in our Gregory gathering system and our Gregory processing plant through the margins earned by purchasing, gathering, transporting and reselling natural gas, and through the incremental margin, if any, generated by processing the portion of the gas for which we retain the processing risk. As of June 30, 2003, we were purchasing gas from over 65 producers primarily pursuant to month-to-month contracts, and for the six months ended June 30, 2003, approximately 96% of the natural gas volumes we purchased were purchased at a fixed price relative to an index and the remainder were purchased at percentage of an index. The first 100,000 MMBtu of the processed natural gas from our Gregory processing plant is sold to a subsidiary of Kinder Morgan pursuant to a contract expiring in 2006 at a price based on a fixed price relative to a monthly index. Liquids produced are sold under two contracts, one expiring in 2007, and the other expiring in March 2004.

Gregory Processing Plant. Our Gregory processing plant is a cryogenic turbo-expander with a 210,000 gallon per day fractionator that removes liquid hydrocarbons from the liquids-rich gas produced into the Gregory gathering system. Our Gregory processing plant has an inlet capacity of approximately 90,000 Mcf/d and average throughput was approximately 93,654 MMBtu/d for the six months ended June 30, 2003. At the time of our acquisition, the plant was processing approximately 43,400 MMBtu/d of gas per day. We are nearing completion of an expansion to the processing plant which will increase the capacity to 150,000 Mcf/d. The Gregory processing plant was constructed in the 1980s and expanded and upgraded in 1998. We believe the expected remaining life of the Gregory processing plant is approximately 20 years.

In addition to the margins generated by the Gregory gathering system, we generate revenues at our Gregory processing plant under two types of arrangements:

- For the six months ended June 30, 2003, we purchased approximately 22% of the natural gas volumes on our Gregory system under contracts in which we were exposed to the risk of loss or gain in processing the natural gas. Under these contracts, we fractionate the NGLs into separate NGL products, which we then sell at prices based upon the market price for NGL products. All of the processed natural gas is delivered to a single customer at a price based on a fixed price relative to a monthly index. This contract expires in March 2006. Since we extract Btus from the gas stream in the form of the liquids or consume it as fuel during processing, we reduce the Btu content of the natural gas but seek to more than offset this by creating value from the separated NGL products. Accordingly, our margins under these arrangements can be negatively affected in periods where the value of natural gas is high relative to the value of NGLs.

- For the six months ended June 30, 2003, we purchased approximately 78% of the natural gas volumes on our Gregory system at a spot or market price less a discount that includes a fee for processing and marketing the natural gas and NGLs at our Gregory processing plant with no risk of loss or gain in processing the natural gas. Under these contracts, the producer retains ownership of the fractionated NGLs, and accordingly bears the risk and retains the benefits associated with processing the natural gas.

Arkoma Gathering System. We acquired the Arkoma gathering system, located in the southeastern region of Oklahoma, in September 2000 for $10.5 million. In addition, since acquiring this system, we have acquired the Shawnee extension, consisting of 15 miles of gathering pipelines extending through additional supply areas in this region. The Arkoma gathering system when acquired was approximately 84 miles in length and included a 3,700 horsepower compressor station. With the addition of the Shawnee extension and additional well connections, the system is now approximately 100 miles in length and ranges in diameter from two to 10 inches. This low-pressure system gathers gas from approximately 158 wells to three compressor stations for discharge to a mainline transmission pipeline. This system has a capacity of 20,000 Mcf/d and average throughput was approximately 10,670 MMBtu/d for the six months ended June 30, 2003.

We generate a margin for gathering and transporting gas in the Arkoma gathering system equal to a percentage of the proceeds from the sale of the natural gas into the mainline transmission pipeline. We take title to the gas at the metering point into the gathering system, with payment based upon an allocation of the metered volume sold into the mainline transmission facilities of our customer with the producer sharing their pro rata portion of the fuel costs for the compression and the removal of water from the natural gas stream.

AIM Pipeline System. We acquired the AIM pipeline system from DEFS in June 2003 in connection with the DEFS acquisition. The AIM pipeline system is located in 15 counties of south Mississippi spanning from the city of Jackson in the northwest to Hattiesburg in the southeast. The system has wellhead supply connections in most of the gas fields in the counties of operation—primarily Jasper, Jefferson Davis, Lawrence, Marion and Simpson counties. The system delivers natural gas through direct market connections to utilities and industrial end users. The pipeline system consists of approximately 638 miles of pipeline ranging in diameter from four to 20 inches with a total estimated capacity of 195,000 Mcf/d. Average throughput on this system was approximately 84,000 MMBtu/d at the time of our acquisition. The system was constructed in the 1970s and we believe the expected remaining life of the pipeline system is approximately 30 years.

We generate operating profits in our AIM pipeline system by purchasing, gathering, transporting and reselling natural gas. We purchase gas from approximately 60 producers at the delivery points into the system. The majority of contracts are priced at a fixed basis to an area index.

Seminole Gas Processing Plant. We own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon dioxide under a long-term arrangement. Revenues at the plant are derived from a fee it charges producers, including those at the Seminole San Andres unit, for each Mcf of carbon dioxide returned to the producer for reinjection. The fees currently average $0.5834 for each Mcf of carbon dioxide returned. Reinjected carbon dioxide is used in a tertiary oil recovery process in the field. The plant also receives 50% of the NGLs produced by the plant. We have entered into a one-year contract with Duke Energy NGL Services, L.P. to market our NGLs on our behalf, and receive our share of proceeds from the sale of carbon dioxide from the plant operator. We are separately billed by the plant operator for our share of expenses. The plant had capacity of 150,000 Mcf/d at the time of acquisition with an approved expansion of 60,000 Mcf/d underway to increase capacity to 210,000 Mcf/d. Average throughput for the plant was approximately 149,000 Mcf/d at the time of our acquisition. The plant was constructed in the 1980s and we believe the expected remaining life of the pipeline system is approximately 30 years.

Conroe Gas Plant And Gathering System. We acquired the Conroe gas plant and gathering system in June 2003 in connection with the DEFS asset acquisition. Located in Montgomery County, Texas, the Conroe gas plant is a cryogenic gas processing plant with 10 miles of gathering pipelines located within the Conroe Field Unit, which is operated by ExxonMobil. The plant gathers low pressure and high pressure natural gas through contracts with over 20 producers. The plant has outlet natural gas connections to Kinder Morgan Texas Pipeline, L.P. and Copano Field Services. Recovered NGLs are delivered into the Chaparral NGL pipeline. The plant has a capacity of 65,000 Mcf/d and average throughput on this system was approximately 29,000 Mcf/d at the time of our acquisition. The Conroe gas plant was constructed in the 1930s and we believe the expected remaining life of the pipeline system is approximately 20 years.

We generate operating profits at our Conroe gas plant primarily from compression and processing fees and from retaining 40% of the NGLs from the recycled lift gas.

Black Warrior Pipeline System. We acquired the Black Warrior pipeline system in June 2003 in connection with the DEFS asset acquisition. The system is located in Fayette, Lamar, Picken and Tuscaloosa Counties in west-central Alabama. The system gathers coalbed methane gas from the Black Warrior Basin and other conventional wells. The system is a series of three natural gas gathering and transmission systems consisting of approximately 125 miles of four to twelve inch pipeline with an estimated capacity of 70,000 Mcf/d. One supplier to the system accounted for over half of the gas gathered. We deliver the gas primarily to industrial end users. Average throughput on this system was approximately 13,000 Mcf/d at the time of our acquisition. The system was constructed in the 1970s and we believe the remaining life of the pipeline system is approximately 15 years.

We generate operating profits in our Black Warrior pipeline system by gathering, transporting and reselling natural gas. All gas is purchased at the delivery points into the system. The majority of the contracts are priced at a fixed basis to an area index.

Other Systems. We own several small gathering systems totaling approximately 135 miles, including our Manziel system in Wood County, Texas, our San Augustine system in San Augustine County, Texas, our Freestone Rusk system in Freestone County, Texas our Jack Starr and North Edna systems in Jackson County, Texas and our Cadeville and Aurora Centana systems in Louisiana. Through Crosstex Pipeline Partners, a limited partnership of which we are the co-general partner, we own a 28% interest in five gathering systems in east Texas, totaling 64 miles with a combined capacity of 112,000 Mcf/d. We also own five industrial bypass systems each of which supplies natural gas directly from a pipeline to a dedicated customer. The combined volumes for these five industrial bypass systems was approximately 4,750 MMBtu/d for the six months ended June 30, 2003. In addition to these

systems, we own various smaller gathering and transmission systems located in Texas, New Mexico and Louisiana.

Producer Services. We currently purchase for resale volumes of natural gas that do not move through our gathering, processing or transmission assets from over 50 independent producers. We engage in such activities on more than 30 interstate and intrastate pipelines with a major emphasis on Gulf Coast pipelines. We focus on supply aggregation transactions in which we either purchase and resell gas and thereby eliminate the need of the producer to engage in the marketing activities typically handled by in-house marketing or supply departments of larger companies, or act as agent for the producer.

Our business strategy includes developing relationships with natural gas producers to facilitate the purchase of their production on a long-term basis. We believe that this business also provides us with strategic insights and valuable market intelligence which may impact our expansion and acquisition strategy.

We offer to our customers the ability to hedge their purchase or sale price by agreeing to sell to us or to purchase from us volumes of natural gas. This risk management tool enables our customers to reduce pricing volatility associated with the sale and purchase of natural gas. When we agree to purchase or sell natural gas from a customer, we contemporaneously execute a contract for the sale or purchase of such natural gas, or we enter into an offsetting obligation under futures contracts on the New York Mercantile Exchange or by using over-the-counter derivative instruments with third parties.

Treating Division

As of June 30, 2003, we owned 55 treating plants, 32 of which were operated by our personnel, 10 of which were operated by producers, and 13 of which were held in inventory. We entered the treating business in 1998 with the acquisition of WRA Gas Services. In October 2001, we completed our largest acquisition of gas treating assets with the acquisition of Millennium Gas Services, Inc., which added 11 treating plants, four of which were in operation and seven of which were placed in our inventory. With these two acquisitions and the acquisition of additional plants, we have one of the largest gas treating operations in the Texas Gulf Coast. The treating plants remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced to transportation systems to ensure that it meets pipeline quality specifications. Natural gas from certain formations in the Texas Gulf Coast as well as other locations are high in carbon dioxide. The majority of our active plants are treating gas from the Wilcox and Edwards formations in the Texas Gulf Coast, both of which are deeper formations that are high in carbon dioxide. Our active treating facilities include 41 amine plants and two hydrogen sulfide scavenger installations. In cases where producers pay us to operate the treating facilities, we either charge a fixed rate per Mcf of natural gas treated or charge a fixed monthly fee.

In addition to our treating plants, we have three gathering systems with an aggregate of 43 miles of gathering pipeline located in Val Verde, Crockett, Dewitt and Live Oak counties, Texas that are connected to approximately 73 producing wells. These gathering systems are connected to three of our treating plants. The diameter of these gathering pipelines ranges from two to six inches. These gathering assets in the aggregate have a capacity of 65,000 Mcf/d and average throughput was approximately 21,700 Mcf/d for the six months ended June 30, 2003. In cases where we both gather and treat natural gas, our fee is generally based on throughput.

A component of our strategy is to purchase used plants and then refurbish and repair them at our shop and seven-acre yard in Victoria, Texas and our 14-acre yard in Odessa, Texas. We believe that we can purchase used plants and recondition them at a significant cost savings to purchasing new plants. We have an inventory of plants of varying sizes which can be deployed after refurbishment. We also mount most of the plant equipment on skids allowing them to be moved in a timely and cost efficient manner. At such time as our active plants come offline, we will put them in our inventory pending

redeployment. We believe our plant inventory gives us an advantage of several weeks in the time required to respond to a producer's request for treating services.

Treating process. The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. Amine has a chemical affinity for hydrogen sulfide and carbon dioxide that allows it to absorb the impurities from the gas. After mixing, gas and amine are separated and the impurities are removed from the amine by heating. Treating plants are sized by the amine circulation capacity in terms of gallons per minute. The size range of the 42 amine plants in operation is 3.5 to 300 gallons per minute, and the size range of the 13 plants in inventory is 3.5 to 1,000 gallons per minute.

Hydrogen sulfide scavenger facilities use a liquid or solid chemical that reacts with hydrogen sulfide thereby removing it from the gas. Used chemicals are disposed of and cannot be regenerated as amine can. The facilities are primarily vertical towers mounted on concrete foundations. As of June 30, 2003, we had two such facilities which were operated by the producer.

Risk Management

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

Competition

The natural gas gathering, transmission, treating, processing and marketing industries are highly competitive. We face strong competition in acquiring new natural gas supplies. Our 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 the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. The main difference between us and our competitors is that we offer most midstream services, while our competitors typically offer only a few select services. Many of our competitors have capital resources and control supplies of natural gas substantially greater than ours. Our major competitors in the Texas Gulf Coast area for natural gas supplies and markets include El Paso Field Services, Kinder Morgan Inc., Houston Pipeline Company and Duke Energy Field Services. Our major competitors in Mississippi for natural gas supplies and markets include Southern Natural Gas and Gulf South Pipeline Company.

Our gas treating and processing operations face competition from manufacturers of new treating plants and from a small number of regional operators that provide plant leasing and operations similar to ours. We also face competition from vendors of used equipment that occasionally lease and operate plants for producers. Our primary competitor for natural gas treating services in our principal market area is The Hanover Company.

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

Natural Gas Supply

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

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. We do not own any interstate natural gas pipelines, so FERC does not directly regulate any of our operations. However, FERC's regulation influences certain aspects of our business and the market for our products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- 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.

Intrastate Pipeline Regulation. Our intrastate natural gas pipeline operations generally are not subject to rate regulation by FERC, but they are subject to regulation by various agencies of the states in which they are located. However, to the extent that our intrastate pipeline systems transport natural gas in interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

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

Our operations in New Mexico, where we own a private line that is used to serve one customer, are not regulated by the New Mexico Public Regulation Commission. Similarly, our eighty-four mile gathering line in Oklahoma is not regulated by the Oklahoma Corporation Commission. While it is possible that Oklahoma or New Mexico may try to assert jurisdiction on these lines, it is not likely that the assertion of that jurisdiction would have a significant effect on our operations in those states because both states tend to have light-handed regulation of natural gas pipeline facilities.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

We are subject to state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

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

Sales of Natural Gas. The price at which we sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of FERC's more recent proposals may

adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

Environmental Matters

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

Any failure to comply with applicable environmental laws and regulations, including those relating to obtaining required governmental approvals, may result in the assessment of administrative, civil, or criminal penalties, imposition of investigatory or remedial activities and, in less common circumstances, issuance of injunctions or construction bans or delays. While we believe that we currently hold material governmental approvals required to operate our major facilities, we are currently evaluating and updating permits for certain of our facilities that primarily were obtained in recent acquisitions. As part of the regular overall evaluation of our operations, we have implemented procedures and are presently working to ensure that all governmental approvals for both recently acquired facilities and existing operations are updated, as may be necessary. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial condition.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with our operations and we cannot assure you that we will not incur significant costs and liabilities as a result of such upsets, releases, or spills, including those relating to claims for damage to property and persons. In the event of future increases in costs, we may be unable to pass on those increases to our customers. A discharge of hazardous substances or wastes into the environment could, to the extent the event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and claims made by neighboring landowners and other third parties for personal injury or damage to property. We will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly in order to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance.

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

We also generate both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. From time to time, the Environmental Protection Agency, or EPA, has considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. However, it is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements. Changes in applicable regulations may result in an increase in our capital expenditures or plant operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been used over the years for natural gas gathering and processing and for NGL fractionation, transportation and storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom we had no control as to such entities' handling of hydrocarbons or other wastes and the manner in which such substances may have been disposed of or released. These properties and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination or to perform remedial operations to prevent future contamination.

We recently acquired several assets from DEFS that have environmental contamination, including a gas plant in Conroe, Texas; a compressor station in Cadeville, Louisiana; and a compressor station in Millport, Alabama (known as the Millport-McGee Compressor Station). At each of these sites, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/or remediation is underway to address those impacts. The estimated remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million, and the remediation cost for the Cadeville site is currently estimated to be approximately $1.2 million. Under our purchase agreement, Duke has retained liability for cleanup of both the Conroe and Cadeville sites. Moreover, the remediation costs associated with the Conroe site will be covered by agreements with TRC Companies and AIG. Therefore, we do not expect to incur any material environmental liability associated with the Conroe or Cadeville sites. The estimated cost to

investigate and remediate the Millport-McGee site, for which we are responsible, is currently estimated to be approximately $330,000.

Air Emissions. Our operations are subject to the Clean Air Act and comparable state statutes. Amendments to the Clean Air Act were enacted in 1990. Moreover, recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas require or will require most industrial operations in the United States to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies. As a result of these amendments, our processing and fractionating plants, pipelines, and storage facilities that emit volatile organic compounds or nitrogen oxides may become subject to increasingly stringent regulations, including requirements that some sources install maximum or reasonably available control technology. Such requirements, if applicable to our operations, could cause us to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission-related issues. In addition, the 1990 Clean Air Act Amendments established a new operating permit for major sources, which applies to some of our 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 results of operations.

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

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

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered species or their habitats. While we have no reason to believe that we operate in any area that is currently designed as habitat for endangered or threatened species, the discovery of previously unidentified endangered species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Safety Regulations. Our pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, as amended, or HLPSA, 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. We believe that our pipeline operations are in substantial compliance with applicable HLPSA 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 will not have a material adverse effect on our results of operations or financial positions.

Title to Properties

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

Our general partner believes that we have satisfactory title to all of our assets. Title to property may be subject to encumbrances. Our general partner believes that none of such encumbrances should materially detract from the value of our properties or from our interest in these properties or should materially interfere with their use in the operation of our business.

Office Facilities

In addition to our gathering and treating facilities discussed above, we occupy approximately 17,172 square feet of space at our executive offices in Dallas, Texas under a lease expiring in November 2004. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

Employees

As of August 25, 2003, we had approximately 183 full-time employees, including 23 employees who previously worked for DEFS. Approximately half of our employees are general and administrative, engineering, accounting and commercial personnel and the remainder are operational employees. We are not party to any collective bargaining agreements, and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Litigation

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

MANAGEMENT

Management of Crosstex Energy, L.P.

Crosstex Energy GP, LLC, as the general partner of our general partner, manages our operations and activities on behalf of our general partner. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis in the future. Unitholders do not directly or indirectly participate in our management or operations. Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations that are non-recourse.

Three members of the board of directors of Crosstex Energy GP, LLC serve on a conflicts committee to review specific matters which the board of directors believes may involve conflicts of interest. The conflicts committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates and must meet the independence standards to serve on an audit committee of a board of directors established by the Nasdaq National Market. Additionally, the members of the conflicts committee are prohibited from holding any ownership interest in us or in any of our affiliates other than common units. Any matters approved by the conflicts committee are conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

Two members of the board of directors also serve on a compensation committee, which oversees compensation decisions for the officers of our general partner as well as the compensation plans described below. In addition, three members of the board of directors serve on an audit committee that reviews our external financial reporting, is responsible for engaging our independent auditors and reviews procedures for internal auditing and the adequacy of our internal accounting controls. The members of the audit committee must meet the independence standards established by the Nasdaq National Market.

Directors and Executive Officers of Crosstex Energy GP, LLC

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

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis	41	President, Chief Executive Officer and Director
James R. Wales	49	Executive Vice President—Midstream Division
A. Chris Aulds	41	Executive Vice President—Treating Division
Jack M. Lafield	52	Senior Vice President—Business Development
William W. Davis	50	Senior Vice President, Chief Financial Officer and Secretary
Michael P. Scott	48	Senior Vice President—Engineering and Operations
Frank M. Burke	63	Director and Member of the Audit Committee*
C. Roland Haden	62	Director and Member of the Audit and Conflicts* Committees
Bryan H. Lawrence	60	Chairman of the Board
Sheldon B. Lubar	73	Director and Member of the Audit and Compensation* Committees
Robert F. Murchison	48	Director and Member of the Compensation and Conflicts Committees
Stephen A. Wells	59	Director and Member of the Audit and Conflicts Committee

* Indicates chairman of committee.

Barry E. Davis, President, Chief Executive Officer and Director, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of our predecessor. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University.

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

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

party gas supply business segment. Mr. Aulds holds a B.S. degree in Petroleum Engineering from Texas Tech University.

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

William W. Davis, Senior Vice President and Chief Financial Officer, joined our predecessor in September 2001, and has 25 years of finance and accounting experience. Prior to joining our predecessor, Mr. Davis held various positions with Sunshine Mining and Refining Company from 1983 to September 2001, including Vice President—Financial Analysis from 1983 to 1986, Senior Vice President and Chief Accounting Officer from 1986 to 1991 and Executive Vice President and Chief Financial Officer from 1991 to 2001. In addition, Mr. Davis served as Chief Operating Officer in 2000 and 2001. Mr. Davis graduated magna cum laude from Texas A&M University with a B.B.A. in Accounting and is a Certified Public Accountant. Mr. Davis is not related to Barry E. Davis.

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

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

C. Roland Haden joined us as a director upon the completion of our initial public offering. Mr. Haden held the positions of Vice Chancellor of the Texas A&M System, Director of the Texas Engineering Experiment Station and Dean of Look College of Engineering at Texas A&M University from 1993 to 2002. Prior to joining Texas A&M University, Mr. Haden served as Vice Chancellor for Academic Affairs and Provost of Louisiana State University from 1991 to 1993 and held various positions with Arizona State University, including Dean and Professor of Engineering & Applied Sciences from 1989 to 1991, Provost, ASU West Campus from 1988 to 1989, Vice President for Academic Affairs from 1987 to 1988 and Dean and Professor of Engineering and Applied Sciences from 1978 to 1987. Mr. Haden formerly served as a director of Square D Company, a Fortune 500 electrical manufacturing company, as a director of E-Systems, a Fortune 500 defense contractor, and as a member of the Telecommunications Advisory Board of A.T. Kearney, a nationally ranked consulting firm. He has been a director of Inter-tel, Inc., a leading telecommunications company, since 1983.

Mr. Haden holds a bachelor's degree from the University of Texas, Arlington, a Masters degree from the California Institute of Technology, and a Ph.D. from the University of Texas, Austin, all in electrical engineering.

Bryan H. Lawrence, Chairman of the Board, joined our predecessor as a director in May 2000. Mr. Lawrence is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships, which make investments in companies engaged in the energy industry. The Yorktown partnerships were formerly affiliated with the investment firm of Dillon, Read & Co. Inc., where Mr. Lawrence had been employed since 1966, serving as a Managing Director until the merger of Dillon Read with SBC Warburg in September 1997. Mr. Lawrence also serves as a director of Carbon Energy Corporation, D&K Healthcare Resources, Inc., Hallador Petroleum Company, TransMontaigne Inc., and Vintage Petroleum, Inc. (each a United States publicly traded company) and Cavell Energy Corp. (a Canadian publicly traded company) and certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests including PetroSantander Inc., Savoy Energy, L.P., Athanor Resources Inc., Camden Resources, Inc., ESI Energy Services Inc., Ellora Energy Inc., and Dernick Resources Inc. Mr. Lawrence is a graduate of Hamilton College and also has an M.B.A. from Columbia University.

Sheldon B. Lubar joined us as a director upon the completion of our initial public offering. Mr. Lubar has been Chairman of the Board of Lubar & Co. Incorporated, a private investment and venture capital firm he founded, since 1977. He was Chairman of the Board of Christiana Companies, Inc., a logistics and manufacturing company, from 1987 until its merger with Weatherford International in 1995. Mr. Lubar has also been a Director of C2, Inc., a logistics and manufacturing company, since 1995, MGIC Investment Corporation, a mortgage insurance company, since 1991, Grant Prideco, Inc., an energy services company, since 2000, and Weatherford International, Inc., an energy services company, since 1995. Mr. Lubar holds a bachelor's degree in Business Administration and a Law degree from the University of Wisconsin—Madison. He was awarded an honorary Doctor of Commercial Science degree from the University of Wisconsin—Milwaukee.

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

Stephen A. Wells joined us as a director upon the completion of our initial public offering. Mr. Wells has been the President of Wells Resources, Inc., a private oil, gas and ranching company since 1983. Mr. Wells has served in executive management positions with various energy companies, with an emphasis in oil field services. He served as Chief Executive Officer and director of Grasso Corporation, a contract production management company, from 1992 to 1994, Chief Executive Officer and director of Coastwide Energy Services, Inc. from 1993 to 1996, and President, Chief Executive Officer and director of Wells Strathclyde Company, an oil field services company he co-founded from 1978 to 1982. Mr. Wells also serves as a director and audit committee chair of Oil States International and as a director and audit committee chair of Pogo Producing Company. Mr. Wells holds a bachelor's degree in accounting from Abilene Christian University.

Reimbursement of Expenses of the General Partner

Our general partner does not receive any management fee or other compensation for its management of our partnership. Our general partner and its affiliates are reimbursed for expenses incurred on our behalf. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, us. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. For the twelve month period ending in December 2003, the amount which we will reimburse the general partner and its affiliates for costs incurred with respect to the general and administrative services performed on our behalf will not exceed $6.0 million. This reimbursement cap does not apply to the cost of any third-party legal, accounting or advisory services received, or the direct expenses of management incurred, in connection with acquisition or business development opportunities evaluated on behalf of the partnership. On December 31, 2003, the $6.0 million limit on such reimbursements will expire and expenses will most likely be higher.

Compensation of Directors

Each director of Crosstex Energy GP, LLC who is not an employee of Crosstex Energy GP, LLC (except Mr. Lawrence) is paid an annual retainer fee of $25,000. Directors do not receive an attendance fee for each board meeting, but an attendance fee of $1,000 is paid to each director for each committee meeting he attends. Directors are also reimbursed for related out-of-pocket expenses. Each committee chairman receives $2,500 annually. Barry E. Davis, as an officer of Crosstex Energy GP, LLC, is otherwise compensated for his services and therefore receives no separate compensation for his service as a director. Outside directors are entitled to take all or any portion of their compensation in the form of unit options or restricted units. Outside directors are also entitled to a one-time grant of 10,000 options at the then-existing market price. Each of Messrs. Haden, Lubar, Wells and Murchison were granted 10,000 unit options with exercise prices of $20.00 per unit which vest ratably over a three-year period.

Executive Compensation

The following table sets forth certain compensation information for the Chief Executive Officer and the five other most highly compensated executive officers of the general partner of our general partner in 2002. We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation allocable to us. The named executive officers have also received certain equity-based awards from our general partner's general partner. We were formed in July 2002 but conducted no business until mid-December 2002. As such, the compensation set forth below includes salary and bonus information paid to each of the named executive officers by Crosstex Energy GP, LLC and our predecessor.

Summary Compensation Table

	Annual Compensation(1)				Long Term Compensation Awards	
Name and Principal Position	**Year**	**Salary(1)**	**Bonus(2)**	**Other Annual Compensation**	**Shares Underlying Options(3)**	**All Other Compensation**
Barry E. Davis *President and Chief Executive Officer*	2002	$ 201,500	$ 100,750	—	30,000	—
James R. Wales *Executive Vice President—Midstream Division*	2002	$ 171,064	$ 59,872	—	20,000	—
A. Chris Aulds *Executive Vice President—Treating Division*	2002	$ 171,064	$ 59,872	—	20,000	—
Jack M. Lafield *Senior Vice President—Business Development*	2002	$ 160,875	$ 56,306	—	17,500	—
William W. Davis *Senior Vice President and Chief Financial Officer*	2002	$ 160,875	$ 96,306	—	17,500	—
Michael P. Scott *Senior Vice President—Engineering and Operations*	2002	$ 134,304	$ 47,007	—	12,500	—

(1) Reflects the aggregate salary paid by Crosstex Energy GP, LLC and our predecessor for fiscal 2002. The portion of the amount shown paid by us subsequent to the closing of our initial public offering on December 17, 2002 for each of Messrs. Davis, Wales, Aulds, Lafield, W. Davis, and Scott was $8,396, $7,128, $7,128, $6,703, $6,703 and $5,596, respectively.

(2) Performance bonuses were earned by the executive officers for service to our predecessor prior to the closing of our initial public offering.

(3) Executive officers have received equity-based awards from our general partner. No awards have vested to date under our Long-Term Incentive Plan. For a description of awards granted to date under the Long-Term Incentive Plan. See "—Long-Term Incentive Plan" beginning on page 92.

Option Grants

The following table contains information about unit option grants to the named executive officers for the year ended December 31, 2002 (except as indicated):

Option Grants in Last Fiscal Year

	Individual Grants					Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
Name	**Number of Securities Underlying Options/SARs Granted(1)**	**Percent of Total Options/ SARs Granted to Employees in Fiscal Year(2)**	**Exercise or Base Price**	**Market Price on Date of Grant**	**Expiration Date**	**5%**	**10%**
Barry E. Davis	30,000	17.1%	$ 20.00	$ 20.00	12/17/12	$ 377,337	$ 956,245
James R. Wales	20,000	11.4%	20.00	20.00	12/17/12	251,558	637,497
A. Chris Aulds	20,000	11.4%	20.00	20.00	12/17/12	251,558	637,497
Jack M. Lafield	17,500	10.0%	20.00	20.00	12/17/12	220,113	557,810
William W. Davis	17,500	10.0%	20.00	20.00	12/17/12	220,113	557,810
Michael P. Scott	12,500	7.1%	20.00	20.00	12/17/12	157,224	398,436

(1) All options were granted pursuant to the Crosstex Energy GP, LLC Long-Term Incentive Plan.

(2) The total number of options granted to employees in 2002 used to calculate these percentages includes 175,000 common units underlying options granted upon the closing of our initial public offering. The options vest at a rate of one-third per year beginning December 17, 2003.

Option Exercises and Year-End Option Values

The following table provides information about the number of units issued upon option exercises by the named executive officers during 2002, and the value realized by the named executive officers. The table also provides information about the number and value of options that were held by the named executive officers at December 31, 2002.

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

Name	Shares Acquired on Exercise	Value Realized	Number of Securities Underlying Unexercised Options at December 31, 2002		Value of Unexercised In-the-Money Options at December 31, 2002(1)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Barry E. Davis	—	—	—	30,000	—	$ 42,000
James R. Wales	—	—	—	20,000	—	28,000
A. Chris Aulds	—	—	—	20,000	—	28,000
Jack M. Lafield	—	—	—	17,500	—	24,500
William W. Davis	—	—	—	17,500	—	24,500
Michael P. Scott	—	—	—	12,500	—	17,500

(1) Based on the $21.40 per unit fair market value of our common units on December 31, 2002, the last trading day of 2002, less the option exercise price.

Employment Agreements

The executive officers of the general partner of our general partner, including Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield, William W. Davis and Michael P. Scott, have entered

into employment agreements with Crosstex Energy GP, LLC. The following is a summary of the material provisions of those employment agreements. All of these employment agreements are substantially similar, with certain exceptions as set forth below.

Each of the employment agreements has an initial term that expires two years from the effective date, but will automatically be extended such that the remaining term of the agreements will not be less than one year. The employment agreements provide for a base annual salary of $201,500, $171,064, $171,064, $160,875, $160,875 and $134,304 for Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield, William W. Davis and Michael P. Scott, respectively.

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

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

Long-Term Incentive Plan

Crosstex Energy GP, LLC established a long-term incentive plan for employees and directors of Crosstex Energy GP, LLC and its affiliates who perform services for us.

The long-term incentive plan consists of two components: restricted units and unit options. The long-term incentive plan currently permits the grant of awards covering an aggregate of 700,000 common units, 233,000 of which may be awarded in the form of restricted units and 467,000 of which may be awarded in the form of unit options. The plan is administered by the compensation committee of Crosstex Energy GP, LLC's board of directors.

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

Restricted Units. A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equivalent to the value of a common unit. At the time of this offering, we will not grant any restricted units. In the future, the compensation committee may make additional grants under the plan to employees and directors containing such terms as the compensation committee shall determine under the plan. The committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted units will vest upon a change of control of us, our general partner or Crosstex Energy GP, LLC.

If a grantee's employment or membership on the board of directors terminates for any reason, the grantee's restricted units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. Common units to be delivered upon the vesting of restricted units may be common units acquired by Crosstex Energy GP, LLC in the open market, common units already owned by Crosstex Energy GP, LLC, common units acquired by Crosstex Energy GP, LLC directly from us or any other person or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. The compensation committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units.

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

In May 2003, our board of directors and compensation committee approved the grant of 43,000 restricted units, including 11,000 restricted units to Barry E. Davis, 7,000 restricted units to each of James R. Wales and A. Chris Aulds, 7,000 restricted units to Jack M. Lafield and William W. Davis and 4,000 restricted units to Michael P. Scott.

Unit Options. The long-term incentive plan currently permits the grant of options covering common units. Unit options will have an exercise price that, in the discretion of the compensation committee, may be less than, equal to or more than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, the unit options will become exercisable upon a change in control of us, our general partner or Crosstex Energy GP, LLC or upon the achievement of specified financial objectives.

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

Grants of options to purchase a total of 175,000 common units were made upon the closing of the initial public offering, including 30,000 to Barry E. Davis, 20,000 to each of James R. Wales and A. Chris Aulds, 17,500 to each of Jack M. Lafield and Willliam W. Davis and 12,500 to Michael P. Scott.

Short-Term Incentive Plan

Crosstex Energy GP, LLC has established a short-term incentive plan for management and other employees who perform services for us. The short-term incentive plan will be administered by the compensation committee. The short-term incentive plan is designed to enhance our financial performance by rewarding management and employees with cash awards for achieving certain performance objectives, including partnership financial targets, individual performance targets or a combination of both. The performance objective for each year is recommended by the compensation committee of the board of directors. Individual participants and payments each year are determined by and in the discretion of the compensation committee, and the compensation committee will be able to amend the plan at any time.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table shows the beneficial ownership of units of Crosstex Energy, L.P. as of June 30, 2003 held by:

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

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Crosstex Energy Holdings Inc.	333,000	12.6%	4,667,000	100.0%	68.5%
Barry E. Davis(2)(3)	11,000	*	—	—	*
James R. Wales(2)(3)	7,000	*	—	—	*
A. Chris Aulds(2)(3)	7,000	*	—	—	*
Jack M. Lafield(2)(3)	7,000	*	—	—	*
William W. Davis(2)(3)	7,000	*	—	—	*
Michael P. Scott(2)(3)	4,000	*	—	—	*
Frank M. Burke	—	—	—	—	—
C. Roland Haden(4)	2,500	*	—	—	*
Bryan H. Lawrence(5)	—	—	—	—	—
Sheldon B. Lubar(6)	—	—	—	—	—
Stephen A. Wells	5,000	*	—	—	*
Robert F. Murchison(7)	25,000	*	—	—	*
All directors and executive officers as a group (12 persons)	75,500	2.9%	—	—	*

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 600, Dallas, Texas 75201, except for Crosstex Energy Holdings Inc. and Bryan H. Lawrence which is 410 Park Avenue, New York, New York 10022.

(2) Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield, William W. Davis and Michael P. Scott each hold an ownership interest in Crosstex Energy Holdings Inc. as indicated in the following table.

(3) Units shown are restricted units granted to executive officers under the Crosstex Energy GP, LLC Long-Term Incentive Plan. Grants of options to purchase a total of 175,000 common units were made upon the closing of the initial public offering to employees of Crosstex Energy GP, LLC, including the named executive officers. See "—Long-Term Incentive Plan" beginning on page 92.

(4) These units are held in a trust for the benefit of the Mr. Haden's children. Mr. Haden and his spouse are trustees of the trust.

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

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

(7) These units are held by Murchison Capital Partners, L.P. Mr. Murchison is the President of the Murchison Management Corp., which serves as the general partner of Murchison Capital Partners, L.P.

The following table shows the beneficial ownership of Crosstex Energy Holdings Inc. as of June 30, 2003. Crosstex Energy Holdings Inc. owns Crosstex Energy GP, LLC and, together with Crosstex Energy GP, LLC, our general partner and, as reflected above, common units and subordinated units.

Name of Beneficial Owner(1)	Percent of Equity

Yorktown Energy Partners IV, L.P.(2)	61.6%
Yorktown Energy Partners V, L.P.(2)	15.4%
Lubar Nominees(3)	6.0%
Barry E. Davis(4)	6.8%
James R. Wales(4)	2.6%
A. Chris Aulds(4)	4.0%
Jack M. Lafield(4)	*
William W. Davis(4)	*
Michael P. Scott(4)	*
Frank M. Burke	—
C. Roland Haden	—
Bryan H. Lawrence(5)	—
Sheldon B. Lubar(3)	6.0%
Stephen A. Wells	—
Robert F. Murchison	—
All directors and executive officers as a group (12 persons)(4)	20.9%

* Less than 1%.

(1) Unless otherwise indicated, the address of each person listed above is 2501 Cedar Springs, Suite 600, Dallas, Texas 75201.

(2) The address for Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. is 410 Park Avenue, New York, New York 10022.

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

(4) Ownership percentage for such individual or group includes shares issuable pursuant to stock options which are presently exercisable or exercisable within 60 days.

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

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Our General Partner

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

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.50 per unit, 23% of the amounts we distribute in excess of $0.625 per unit and 48% of amounts we distribute in excess of $0.75 per unit.

Relationship with Crosstex Energy Holdings Inc.

General. Crosstex Energy Holdings Inc. owns 333,000 common units and 4,667,000 subordinated units representing an aggregate 55.7% limited partner interest in us upon completion of this offering. Our general partner owns a 2% general partner interest in us and the incentive distribution rights. Our general partner's ability, as general partner, to manage and operate Crosstex Energy, L.P. and Crosstex Energy Holdings' ownership of an aggregate 55.7% limited partner interest in us upon completion of this offering effectively gives our general partner the ability to veto some of our actions and to control our management.

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

Initial Public Offering and Concurrent Transactions

On December 17, 2002, we completed an initial public offering of 2,300,000 common units representing limited partner interests and received therefrom net proceeds of approximately $40.2 million. Concurrently with the closing of the initial public offering, certain transactions were consummated in connection with the formation of the Partnership. These transactions involved the transfer to us by Crosstex Energy Holdings Inc. of substantially all the assets and liabilities of Crosstex Energy Services, Ltd. (the predecessor of our operating partnership Crosstex Energy Services, L.P.) in exchange for and the right to receive $2.5 million from the proceeds of the initial public offering and the issuance of 333,000 common units and 4,667,000 subordinated units (which are held by Crosstex Energy Holdings Inc.) and the incentive distribution rights and a 2%

general partner interest in Crosstex Energy, L.P. (which are held by Crosstex Energy GP, L.P.). In addition, certain assets and liabilities of Crosstex Energy Services, Ltd. were not contributed to the Partnership, but, instead, were transferred to a subsidiary of Crosstex Energy Holdings Inc. including receivables associated with the Enron Corp. bankruptcy. Also, the Jonesville processing plant, which was largely inactive since the beginning of 2001, and the Clarkson plant, acquired shortly before our initial public offering, were not contributed to the Partnership, but instead were transferred to a subsidiary of Crosstex Energy Holdings Inc.

Related Party Transactions

Camden Resources, Inc. We treat gas for, and purchase gas from, Camden Resources, Inc. Yorktown Energy Partners IV, L.P. has made equity investments in both Camden and Crosstex Energy Holdings Inc. The gas treating and gas purchase agreements we have entered into with Camden are standard industry agreements containing terms substantially similar to those contained in our agreements with other third parties. During the year ended December 31, 2002 and the six months ended June 30, 2003, we purchased natural gas from Camden Resources, Inc. in the amount of approximately $10.1 million and $5.5 million, respectively and received approximately $399,000 and $214,109 in treating fees from Camden Resources, Inc.

Crosstex Pipeline Company. We indirectly own general and limited partner interests in Crosstex Pipeline Partners, L.P. that represent a 28% economic interest. We have entered into various transactions with Crosstex Pipeline Partners, and we believe that the terms of these transactions are comparable to those that we could have negotiated with unrelated third parties. During the year ended December 31, 2002, our predecessor: (1) purchased natural gas from Crosstex Pipeline Partners in the amount of approximately $3.4 million and paid Crosstex Pipeline Partners approximately $27,000 for transportation of natural gas, (2) received a management fee from Crosstex Pipeline Partners in the amount of approximately $125,000 and (3) received approximately $90,000 in distributions from Crosstex Pipeline Partners.

CONFLICTS OF INTEREST AND FIDUCIARY RESPONSIBILITIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including Crosstex Energy Holdings Inc.), on the one hand, and Crosstex Energy, L.P. and its limited partners, on the other hand. The directors and officers of our general partner's general partner, Crosstex Energy GP, LLC, have fiduciary duties to manage our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to Crosstex Energy, L.P. and the unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or any other partner, on the other, our general partner will resolve that conflict. Our partnership agreement contains provisions that give our general partner significantly greater latitude in resolving conflicts of interests than a director of a corporation would have. In effect, these provisions limit our general partner's fiduciary duties to the unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions taken that, without those limitations, might constitute breaches of fiduciary duty. Our general partner may, but is not required to, seek the approval of the conflicts committee of the board of directors of the general partner of our general partner of such resolution.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or the unitholders if the resolution of the conflict is considered to be fair and reasonable to us. Any resolution will be conclusively deemed fair and reasonable to us if that resolution is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Unless the resolution is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider:

- the relative interests of any parties to such conflict and the benefits and burdens related to such interest;
- any customary or accepted industry practices or historical dealings with a particular person or entity;
- generally accepted accounting practices or principles; and
- such additional factors it determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances it considers relevant.

Conflicts of interest could arise in the situations described below, among others.

Actions taken by our general partner may affect the amount of cash available for distribution to unitholders or accelerate the right to convert subordinated units.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;

- cash expenditures;
- borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by our general partner to our unitholders, including borrowings that have the purpose or effect of:

- enabling our general partner to receive distributions on any subordinated units held by it or the incentive distribution rights; or
- hastening the expiration of the subordination period.

For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and our subordinated units, our partnership agreement permits us to borrow funds, which would enable us to make this distribution on all outstanding units. Please read "Cash Distribution Policy—Subordination Period" beginning on page 37.

Our partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us, the operating partnership or its operating subsidiaries.

We will reimburse our general partner and its affiliates for expenses.

We will reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in providing corporate staff and support services to us. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by the general partner in its sole discretion.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets and not against our general partner or its assets or any affiliate of our general partner or its assets. Our partnership agreement provides that any action taken by our general partner to limit its or our liability is not a breach of our general partner's fiduciary duties, even if we could have obtained terms that are more favorable terms without the limitation on liability.

Common unitholders will have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, will not be the result of arm's-length negotiations.

The partnership agreement allows our general partner to pay itself or its affiliates for any services rendered, provided these services are rendered on terms that are fair and reasonable to us. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts and arrangements between us and our general partner and its affiliates are or will be the result of arm's length negotiations.

All of these transactions entered into after the sale of the common units offered in this offering are to be on terms that are fair and reasonable to us.

Our general partner and its affiliates will have no obligation to permit us to use any facilities or assets of our general partner and its affiliates, except as may be provided in contracts entered into specifically dealing with that use. There is no obligation of our general partner and its affiliates to enter into any contracts of this kind.

Common units are subject to our general partner's limited call right.

Our general partner may exercise its right to call and purchase common units as provided in the partnership agreement or assign this right to one of its affiliates or to us. Our general partner may use its own discretion, free of fiduciary duty restrictions, in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read "The Partnership Agreement—Limited Call Right" on page 115.

We may choose not to retain separate counsel for ourselves or for the holders of common units.

The attorneys, independent accountants and others who perform services for us have been retained by our general partner. Attorneys, independent accountants and others who will perform services for us are selected by our general partner or the conflicts committee and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

Our general partner's affiliates may compete with us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. Except as provided in the partnership agreement and the omnibus agreement, affiliates of our general partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

Fiduciary duties owed to unitholders by our general partner are prescribed by law and the partnership agreement.

Our general partner is accountable to us and our unitholders as a fiduciary. Fiduciary duties owed to unitholders by our general partner are prescribed by law and our partnership agreement. The Delaware Revised Uniform Limited Partnership Act, which we refer to in this prospectus as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, restrict or expand the fiduciary duties owed by our general partner to limited partners and the partnership. Delaware law has not definitively established the limits on the ability of the partnership agreement to restrict such fiduciary duty.

Our partnership agreement contains various provisions restricting the fiduciary duties that might otherwise be owed by our general partner. We have adopted these restrictions to allow our general partner to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. We believe this is appropriate and necessary because the board of directors of our general partner's general partner have fiduciary duties to manage our general partner in a manner beneficial both to its owners as well as to you. Without these modifications, the general partner's ability to make decisions involving conflicts of interest would be restricted. The modifications to the fiduciary standards benefit the general partner by enabling it to take into consideration all parties involved in the proposed action, so long as the resolution is fair and reasonable to us as described above. These modifications also enable the general partner of our general partner to attract and retain experienced and capable directors. These modifications represent a detriment to the common unitholders because they restrict the remedies available to unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below. The following is a summary of the material restrictions of the fiduciary duties owed by our general partner to the limited partners:

State-law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for our partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present.
Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, our partnership agreement permits our general partner to make a number of decisions in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Other provisions of the partnership agreement provide that our general partner's actions must be made in its reasonable discretion. These standards reduce the obligations to which our general partner would otherwise be held.
	Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to us under the factors previously set forth. In determining whether a transaction or resolution is "fair and reasonable" our general partner may consider interests of all parties involved, including its own. Unless our general partner has acted in bad faith, the action taken by our general partner shall not constitute a breach of its fiduciary duty. These standards reduce the obligations to which our general partner would otherwise be held.
	In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partner and those other persons acted in good faith.

Rights and Remedies of Unitholders	The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These actions could include actions against a general partner for breach of its fiduciary duties or of the partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

In order to become one of our limited partners, a common unitholder is required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner or assignee to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

We must indemnify our general partner and its officers, directors, employees, affiliates, partners, members, agents and trustees, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification if our general partner or these persons acted in good faith and in a manner they reasonably believed to be in, or (in the case of a person other than our general partner) not opposed to, our best interests. We also must provide this indemnification for criminal proceedings if our general partner or these other persons had no reasonable cause to believe their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it met these requirements concerning good faith and our best interests. To the extent that these provisions purport to include indemnification for liabilities arising under the Securities Act of 1933, in the opinion of the Securities and Exchange Commission, such indemnification is contrary to public policy and therefore unenforceable. If you have questions regarding the fiduciary duties of our general partner, you should consult with your own counsel. Please read "The Partnership Agreement—Indemnification" on page 117.

DESCRIPTION OF THE COMMON UNITS

The Units

The common units and the subordinated units represent limited partner interests in us. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units and subordinated units in and to partnership distributions, please read this section and "Cash Distribution Policy" beginning on page 35. For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please read "The Partnership Agreement" beginning on page 105.

Transfer Agent and Registrar

Duties

American Stock Transfer & Trust Company serves as registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units, except the following that must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a holder of a common unit; and
- other similar fees or charges.

There is no charge to unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and accepted the appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

The transfer of the common units to persons that purchase directly from the underwriters will be accomplished through the completion, execution and delivery of a transfer application by the investor. Any later transfers of a common unit will not be recorded by the transfer agent or recognized by us unless the transferee executes and delivers a transfer application. By executing and delivering a transfer application, the transferee of common units:

- becomes the record holder of the common units and is an assignee until admitted into our partnership as a substituted limited partner;
- automatically requests admission as a substituted limited partner in our partnership;
- agrees to be bound by the terms and conditions of, and executes, our partnership agreement;
- represents that the transferee has the capacity, power and authority to enter into the partnership agreement;

- grants powers of attorney to officers of our general partner and any liquidator of us as specified in the partnership agreement; and
- makes the consents and waivers contained in the partnership agreement.

An assignee will become a substituted limited partner of our partnership for the transferred common units upon the consent of our general partner and the recording of the name of the assignee on our books and records. Our general partner may withhold its consent in its sole discretion.

A transferee's broker, agent or nominee may complete, execute and deliver a transfer application. We are entitled to treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to request admission as a substituted limited partner in our partnership for the transferred common units. A purchaser or transferee of common units who does not execute and deliver a transfer application obtains only:

- the right to assign the common unit to a purchaser or other transferee; and
- the right to transfer the right to seek admission as a substituted limited partner in our partnership for the transferred common units.

Thus, a purchaser or transferee of common units who does not execute and deliver a transfer application:

- will not receive cash distributions or federal income tax allocations, unless the common units are held in a nominee or "street name" account and the nominee or broker has executed and delivered a transfer application; and
- may not receive some federal income tax information or reports furnished to record holders of common units.

The transferor of common units has a duty to provide the transferee with all information that may be necessary to transfer the common units. The transferor does not have a duty to insure the execution of the transfer application by the transferee and has no liability or responsibility if the transferee neglects or chooses not to execute and forward the transfer application to the transfer agent. Please read "The Partnership Agreement—Status as Limited Partner or Assignee" on page 116.

Until a common unit has been transferred on our books, we and the transfer agent, may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. Our partnership agreement, as well as the partnership agreement of the operating partnership, are included as exhibits to the registration statement of which this prospectus constitutes a part. We will provide prospective investors with a copy of the form of this agreement upon request at no charge. Unless the context otherwise requires, references in this prospectus to the "partnership agreement" constitute references to the partnership agreement of Crosstex Energy, L.P.

We summarize the following provisions of the partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please read "Cash Distribution Policy" beginning on page 35;
- with regard to the transfer of common units, please read "Description of the Common Units—Transfer of Common Units" beginning on page 103; and
- with regard to allocations of taxable income and taxable loss, please read "Material Tax Consequences" beginning on page 120.

Organization and Duration

We were organized on July 12, 2002 and will have a perpetual existence except as provided under "—Termination and Dissolution" on page 112.

Purpose

Our purpose under the partnership agreement is limited to serving as the limited partner of the operating partnership and engaging in any business activities that may be engaged in by the operating partnership or that are approved by our general partner. The partnership agreement of the operating partnership provides that the operating partnership may, directly or indirectly, engage in:

- its operations as conducted immediately before our initial public offering;
- any other activity approved by the general partner but only to the extent that the general partner reasonably determines that, as of the date of the acquisition or commencement of the activity, the activity generates "qualifying income" as this term is defined in Section 7704 of the Internal Revenue Code; or
- any activity that enhances the operations of an activity that is described in either of the two preceding clauses or any other activity provided such activity does not affect our treatment as a partnership for Federal income tax purposes.

Although our general partner has the ability to cause us, the operating partnership or its subsidiaries to engage in activities other than gathering, transmission, treating, processing and marketing of natural gas, our general partner has no current plans to do so. Our general partner is authorized in general to perform all acts deemed necessary to carry out our purposes and to conduct our business.

Power of Attorney

Each limited partner, and each person who acquires a unit from a unitholder and executes and delivers a transfer application, grants to our general partner and, if appointed, a liquidator, a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution. The power of attorney also grants our general partner the authority to amend, and to make consents and waivers under, the partnership agreement.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of the partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined, however, that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to the partnership agreement; or
- to take other action under the partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as the general partner. This liability would extend to persons who transact business with us who reasonably believe that the limited partner is a general partner. Neither the partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, an assignee who becomes a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except the assignee is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our subsidiaries conduct business in seven states. Maintenance of our limited liability as a limited partner of the operating partnership may require compliance with legal requirements in the jurisdictions in which the operating partnership conducts business, including qualifying our subsidiaries to do business there. Limitations on the liability of limited partners for the obligations of a limited partner have not been clearly established in many jurisdictions. If, by virtue of our limited partner interest in the operating partnership or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace the general partner, to approve some amendments to the partnership agreement, or to take other action under the partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held

personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Voting Rights

The following matters require the unitholder vote specified below. Certain significant decisions require approval by a "unit majority" of the common units. We define "unit majority" as:

- during the subordination period, at least a majority of the outstanding common units, excluding common units owned by the general partner and its affiliates, voting as a class and at least a majority of the outstanding subordinated units voting as a class; and

- thereafter, at least a majority of the outstanding common units.

Issuance of additional common units or units of equal rank with the common units during the subordination period	Unit majority, with certain exceptions described under "—Issuance of Additional Securities" beginning on page 108.
Issuance of units senior to the common units during the subordination period	Unit majority.
Issuance of units junior to the common units during the subordination period	No approval right.
Issuance of additional units after the subordination period	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. See "—Amendment of the Partnership Agreement" beginning on page 109.
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority. See "—Merger, Sale or Other Disposition of Assets" on pages 111 and 112.
Amendment of the operating partnership agreement and other action taken by us as a limited partner of the operating partnership	Unit majority if such amendment or other action would adversely affect our limited partners (or any particular class of limited partners) in any material respect. See "—Action Relating to the Operating Partnership" on page 111.
Dissolution of our partnership	Unit majority. See "—Termination and Dissolution" on page 112.
Reconstitution of our partnership upon dissolution	Unit majority. See "—Termination and Dissolution" on page 112.

Withdrawal of the general partner	The approval of a majority of the common units, excluding common units held by the general partner and its affiliates, is required in most circumstances for the withdrawal of the general partner prior to December 31, 2012 in a manner which would cause a dissolution of our partnership. See "—Withdrawal or Removal of our General Partner" beginning on page 113.
Removal of the general partner	Not less than $66^{2}/_{3}$% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates. See "—Withdrawal or Removal of our General Partner" beginning on page 113.
Transfer of the general partner interest	Our general partner may transfer all, but not less than all, of its general partner interest in us without a vote of our unitholders to an affiliate or another person in connection with its merger or consolidation with or into, or sale of all our substantially all of its assets to such person. The approval of a majority of the common units, excluding common units held by the general partner and its affiliates, is required in other circumstances for a transfer of the general partner interest to a third party prior to December 31, 2012. See "—Transfer of General Partner Interests" on page 114.

Transfer of incentive distribution rights	Except for transfers to an affiliate or another person as part of the general partner's merger or consolidation with or into, or sale of all or substantially all of its assets to or sale of all or substantially all its equity interests to such person, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates, voting separately as a class, is required in most circumstances for a transfer of the incentive distribution rights to a third party prior to December 31, 2012. See "—Transfer of Incentive Distribution Rights" beginning on page 114.
Transfer of ownership interests in the general partner	No approval required at any time. See "—Transfer of Ownership Interests in our General Partner" on page 114.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional partnership securities and rights to buy partnership securities for the consideration and on the terms and conditions established by our general partner in its sole discretion without the approval of the unitholders. During

the subordination period, however, except as we discuss in the following paragraph, we may not issue equity securities ranking senior to the common units or an aggregate of more than 1,316,500 additional common units or units on a parity with the common units, in each case, without the approval of the holders of a majority of the outstanding common units and subordinated units, voting as separate classes.

During or after the subordination period, we may issue an unlimited number of common units without the approval of unitholders as follows:

- upon exercise of the underwriters' over-allotment option;
- upon conversion of the subordinated units into common units;
- upon conversion of units of equal rank with the common units under some circumstances;
- under employee benefit plans;
- upon conversion of the general partner interest and incentive distribution rights as a result of a withdrawal of our general partner;
- in the event of a combination or subdivision of common units;
- in connection with an acquisition or a capital improvement that increases cash flow from operations per unit on a pro forma basis; or
- if the proceeds of the issuance are used exclusively to repay indebtedness the cost of which to service is greater than the distribution obligations associated with the units issued in connection with its retirement.

It is possible that we will fund acquisitions through the issuance of additional common units or other equity securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional partnership interests may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership securities interests that, in the sole discretion of our general partner, have special voting rights to which the common units are not entitled.

Upon the issuance of additional partnership securities, other than upon exercise of the underwriters' over-allotment option, our general partner will be required to make additional capital contributions to the extent necessary to maintain its 2% general partner interest in us. Moreover, our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other equity securities whenever, and on the same terms that, we issue those securities to persons other than our general partner and its affiliates, to the extent necessary to maintain its percentage interest, including its interest represented by common units and subordinated units, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership securities.

Amendment of the Partnership Agreement

General. Amendments to the partnership agreement may be proposed only by or with the consent of our general partner, which consent may be given or withheld in its sole discretion. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner must seek written approval of the holders of the number of units required to approve the amendment or call a

meeting of the limited partners to consider and vote upon the proposed amendment. Except as we describe below, an amendment must be approved by a unit majority.

Prohibited Amendments. No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected;
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which may be given or withheld in its sole discretion;

- change the term of our partnership;
- provide that our partnership is not dissolved upon an election to dissolve our partnership by our general partner that is approved by a unit majority; or
- give any person the right to dissolve our partnership other than our general partner's right to dissolve our partnership with the approval of a unit majority.

The provision of the partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class.

No Unitholder Approval. Our general partner may generally make amendments to the partnership agreement without the approval of any limited partner or assignee to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;
- the admission, substitution, withdrawal, or removal of partners in accordance with the partnership agreement;
- a change that, in the sole discretion of our general partner, is necessary or advisable for us to qualify or to continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither we, the operating partnership nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees, from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or plan asset regulations adopted under the Employee Retirement Income Security Act of 1974, whether or not substantially similar to plan asset regulations currently applied or proposed;
- subject to the limitations on the issuance of additional partnership securities described above, an amendment that in the discretion of our general partner is necessary or advisable for the authorization of additional partnership securities or rights to acquire partnership securities;
- any amendment expressly permitted in the partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of the partnership agreement;
- any amendment that, in the discretion of our general partner, is necessary or advisable for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;

- a change in our fiscal year or taxable year and related changes; or
- any other amendments substantially similar to any of the matters described in the preceding clauses.

In addition, our general partner may make amendments to the partnership agreement without the approval of any limited partner or assignee if those amendments, in the discretion of our general partner:

- do not adversely affect the limited partners (or any particular class of limited partners as compared to other classes of limited partners) in any material respect;
- are necessary or advisable to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or advisable to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading, compliance with any of which our general partner deems to be in our best interest and the best interest of our limited partners;
- are necessary or advisable for any action taken by our general partner relating to splits or combinations of units under the provisions of the partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval. Our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners or result in our being treated as an entity for federal income tax purposes if one of the amendments described above under "—No Unitholder Approval" should occur. No other amendments to the partnership agreement will become effective without the approval of holders of at least 90% of the units unless we obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners or cause us, the operating partnership or its subsidiaries to be taxable as a corporation or otherwise to be taxed as an entity for federal income tax purposes (to the extent not previously taxed as such).

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action must be approved by the affirmative vote of limited partners constituting not less than the voting requirement sought to be reduced.

Action Relating to the Operating Partnership

Without the approval of holders of units representing a unit majority, our general partner is prohibited from consenting on our behalf, as the limited partner of the operating partnership, to any amendment to the partnership agreement of the operating partnership or taking any action on our behalf permitted to be taken by a limited partner of the operating partnership, in each case that would adversely affect our limited partners (or any particular class of limited partners as compared to other classes of limited partners) in any material respect.

Merger, Sale or Other Disposition of Assets

The partnership agreement generally prohibits our general partner, without the prior approval of the holders of units representing a unit majority, from causing us to, among other things, sell, exchange

or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries as a whole. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval.

If conditions specified in the partnership agreement are satisfied, our general partner may merge us or any of our subsidiaries into, or convey some or all of our assets to, a newly formed entity if the sole purpose of that merger or conveyance is to change our legal form into another limited liability entity. The unitholders are not entitled to dissenters' rights of appraisal under the partnership agreement or applicable Delaware law in the event of a merger or consolidation, a sale of substantially all of our assets or any other transaction or event.

Termination and Dissolution

We will continue as a limited partnership until terminated under the partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- the sale, exchange or other disposition of all or substantially all of our assets and properties and our subsidiaries;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with the partnership agreement or withdrawal or removal following approval and admission of a successor.

Upon a dissolution under the last clause, the holders of a majority of the outstanding common units and subordinated units, voting as separate classes, may also elect, within specific time limitations, to reconstitute us and continue our business on the same terms and conditions described in the partnership agreement by forming a new limited partnership on terms identical to those in the partnership agreement and having as general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner; and
- neither our partnership, the reconstituted limited partnership nor the operating partnership would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are reconstituted and continued as a new limited partnership, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that the liquidator deems necessary or desirable in its judgment, liquidate our assets and apply the proceeds of the liquidation as provided in "Cash Distribution Policy—Distributions of Cash upon Liquidation" beginning on page 41. The liquidator may defer liquidation of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to the partners.

Withdrawal or Removal of our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to December 31, 2012 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after December 31, 2012 our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of the partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than our general partner and its affiliates. In addition, the partnership agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read "—Transfer of General Partner Interests" on page 114.

Upon the withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a majority of the outstanding common units and subordinated units, voting as separate classes, may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within 180 days after that withdrawal, the holders of a majority of the outstanding common units and subordinated units, voting as separate classes, agree in writing to continue our business and to appoint a successor general partner. Please read "—Termination and Dissolution" on page 112.

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than $66^2/_3\%$ of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of the general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units and subordinated units, voting as separate classes. The ownership of more than $33^1/_3\%$ of the outstanding units by our general partner and its affiliates would give it the practical ability to prevent its removal. At the closing of this offering, affiliates of the general partner will own 56.8% of the outstanding units.

The partnership agreement also provides that if Crosstex Energy GP, L.P. is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end and each outstanding subordinated unit will immediately convert into one common unit;

- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at the time.

In the event of removal of the general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates the partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner and its incentive

distribution rights for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest and its incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Our general partner and its affiliates may at any time transfer units to one or more persons, without unitholder approval, except that they may not transfer subordinated units to us.

Transfer of General Partner Interests

Except for transfer by our general partner of all, but not less than all, of its general partner interest in us and the operating partnership to:

- an affiliate of the general partner (other than an individual); or
- another entity as part of the merger or consolidation of our general partner with or into another entity or the transfer by our general partner of all or substantially all of its assets to another entity,

our general partner may not transfer all or any part of its general partner interest in us and the operating partnership to another entity prior to December 31, 2012 without the approval of the holders of at least a majority of the outstanding common units, excluding common units held by the general partner and its affiliates. As a condition of this transfer, the transferee must assume the rights and duties of our general partner, agree to be bound by the provisions of the partnership agreement, and furnish an opinion of counsel regarding limited liability and tax matters.

Transfer of Ownership Interests in our General Partner

At any time, the partners of our general partner may sell or transfer all or part of their partnership interests in the general partner without the approval of the unitholders.

Transfer of Incentive Distribution Rights

Our general partner or its affiliates or a subsequent holder of incentive distribution rights may transfer its incentive distribution rights to an affiliate or to another person as part of its merger or consolidation with or into, or sale of all or substantially all of its assets, or sale of substantially all of its equity interests to, that person without the prior approval of the unitholders; but, in each case, the transferee must agree to be bound by the provisions of the partnership agreement. Prior to December 31, 2012, other transfers of the incentive distribution rights will require the affirmative vote of holders of a majority of the outstanding common units (excluding common units held by the general

partner or its affiliates). On or after December 31, 2012, the incentive distribution rights will be freely transferable.

Change of Management Provisions

The partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Crosstex Energy GP, L.P. as our general partner or otherwise change management. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the board of directors.

Our partnership agreement also provides that if our general partner is removed under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end and each outstanding subordinated unit will immediately convert into one common unit;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Limited Call Right

If at any time our general partner and its affiliates hold more than 80% of the then-issued and outstanding partnership securities of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the remaining partnership securities of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least ten but not more than 60 days notice. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by our general partner or any of its affiliates for any partnership securities of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those partnership securities; and

- the current market price as of the date three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding partnership securities, a holder of partnership securities may have his partnership securities purchased at an undesirable time or price. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please read "Material Tax Consequences—Disposition of Common Units" beginning on page 128.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, unitholders or assignees who are record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited. Common units that are owned by an assignee who is a record holder, but who has not yet been admitted as a limited partner, will be voted by our general partner at the written direction of the record holder. Absent direction of this kind, the common units will not be voted,

except that, in the case of common units held by our general partner on behalf of non-citizen assignees, our general partner will distribute the votes on those common units in the same ratios as the votes of limited partners on other units are cast.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Securities" beginning on page 108. However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Except as the partnership agreement otherwise provides, subordinated units will vote together with common units as a single class.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under the partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner or Assignee

Except as described under "—Limited Liability" on pages 106 and 107 the common units will be fully paid, and unitholders will not be required to make additional contributions.

An assignee of a common unit, after executing and delivering a transfer application, but pending its admission as a substituted limited partner, is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. Our general partner will vote and exercise other powers attributable to common units owned by an assignee that has not become a substitute limited partner at the written direction of the assignee. Please read "—Meetings; Voting" beginning on page 115. Transferees that do not execute and deliver a transfer application will be treated neither as assignees nor as record holders of common units, and will not receive cash distributions, federal income tax allocations or reports furnished to holders of common units. Please read "Description of the Common Units—Transfer of Common Units" beginning on page 103.

Non-citizen Assignees; Redemption

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any

limited partner or assignee, we may redeem the units held by the limited partner or assignee at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner or assignee to furnish information about his nationality, citizenship or related status. If a limited partner or assignee fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner or assignee is not an eligible citizen, the limited partner or assignee may be treated as a non-citizen assignee. In addition to other limitations on the rights of an assignee that is not a substituted limited partner, a non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

Indemnification

Under the partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of a general partner or any departing general partner;
- any person who is or was a member, partner, officer, director, employee, agent or trustee of our general partner or any departing general partner or any affiliate of a general partner or any departing general partner; or
- any person who is or was serving at the request of a general partner or any departing general partner or any affiliate of a general partner or any departing general partner as an officer, director, employee, member, partner, agent or trustee of another person.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees in its sole discretion, our general partner will not be personally liable for, or have any obligation to contribute or loan funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under the partnership agreement.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of common units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 90 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right to Inspect Our Books and Records

The partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each became a partner;
- copies of the partnership agreement, the certificate of limited partnership of the partnership, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under the partnership agreement, we have agreed to register for resale under the Securities Act of 1933 and applicable state securities laws any common units, subordinated units or other partnership securities proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of Crosstex Energy GP, L.P. as our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions. Please read "Units Eligible for Future Sale" on page 119.

UNITS ELIGIBLE FOR FUTURE SALE

Affiliates of our general partner hold 333,000 common units and 4,667,000 subordinated units. All of these subordinated units will convert into common units at the end of the subordination period and some may convert earlier. The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in the offering will generally be freely transferable without restriction or further registration under the Securities Act of 1933, except that any common units owned by an "affiliate" of ours may not be resold publicly other than in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1% of the total number of the securities outstanding; or
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, notice requirements and the availability of current public information about us. A person who is not deemed to have been an affiliate of our company at any time during the three months preceding a sale, and who has beneficially owned his common units for at least two years, would be entitled to sell common units under Rule 144 without regard to the public information requirements, volume limitations, manner of sale provisions and notice requirements of Rule 144.

Prior to the end of the subordination period, we may not issue equity securities of the partnership ranking prior or senior to the common units or an aggregate of more than 1,316,500 additional common units or an equivalent amount of securities ranking on a parity with the common units, without the approval of the holders of a majority of the outstanding common units and subordinated units, voting as separate classes, subject to certain exceptions described under "The Partnership Agreement—Issuance of Additional Securities" beginning on page 108.

The partnership agreement provides that, after the subordination period, we may issue an unlimited number of limited partner interests of any type without a vote of the unitholders. The partnership agreement does not restrict our ability to issue equity securities ranking junior to the common units at any time. Any issuance of additional common units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding. Please read "The Partnership Agreement—Issuance of Additional Securities" beginning on page 108.

Under the partnership agreement, our general partner and its affiliates have the right to cause us to register under the Securities Act of 1933 and state laws the offer and sale of any units that they hold. Subject to the terms and conditions of the partnership agreement, these registration rights allow the general partner and its affiliates or their assignees holding any units to require registration of any of these units and to include any of these units in a registration by us of other units, including units offered by us or by any unitholder. Our general partner will continue to have these registration rights for two years following its withdrawal or removal as our general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors and controlling persons from and against any liabilities under the Securities Act or any state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts and commissions. Except as described below, the general partner and its affiliates may sell their units in private transactions at any time, subject to compliance with applicable laws.

Crosstex Energy, L.P., Crosstex Energy Holdings Inc., our general partner and the directors and executive officers of the general partner of our general partner have agreed not to sell any common units they beneficially own for a period of 90 days from the date of this prospectus. Please read "Underwriting" beginning on page 135 for a description of these lock-up provisions.

MATERIAL TAX CONSEQUENCES

This section discusses the material tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States. It is based upon current provisions of the Internal Revenue Code, existing regulations, proposed regulations to the extent noted, and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to Crosstex Energy, L.P. and the operating partnership.

No attempt has been made in the following discussion to comment on all federal income tax matters affecting us or the unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, nonresident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), real estate investment trusts (REITs), or mutual funds. Accordingly, we recommend that each prospective unitholder consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Thompson & Knight L.L.P., counsel to the general partner and to us, and are, to the extent noted herein, based on the accuracy of certain factual matters.

No ruling has been or will be requested from the IRS regarding any matter affecting us or prospective unitholders. An opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made here may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for the common units and the prices at which the common units trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by the unitholders and our general partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

For the reasons described below, Thompson & Knight L.L.P. has not rendered an opinion with respect to the following specific federal income tax issues:

- the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read "—Tax Consequences of Unit Ownership—Treatment of short sales" beginning on page 125);
- whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read "—Disposition of Common Units—Allocations between transferors and transferees" on page 129); and
- whether our method for depreciating Section 743 adjustments is sustainable (please read "—Tax Consequences of Unit Ownership—Section 754 election" beginning on page 126).

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, even if no cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner's adjusted basis in his partnership interest.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to our status for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Thompson & Knight L.L.P. that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions, that the operating partnership will be disregarded as an entity separate from us for federal income tax purposes so long as the operating partnership and its general partner (which is a limited liability company) do not elect to be treated as a corporation and we will be classified as a partnership so long as:

- We do not elect to be treated as a corporation; and
- For each taxable year, more than 90% of our gross income is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code.

Qualifying income includes certain income and gains derived from the transportation and processing of crude oil, natural gas and products thereof. Other types of qualifying income include interest other than from a financial business, dividends, gains from the sale of real property and gains from the sale or other disposition of assets held for the production of income that otherwise constitutes qualifying income. We estimate that more than 96% of our current income is within one or more categories of income that are qualifying income in the opinion of Thompson & Knight L.L.P. The portion of our income that is qualifying income can change from time to time.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Although we expect to conduct our business so as to meet the Qualifying Income Exception, if we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and as if we had then distributed that stock to the unitholders in liquidation of their interests in us. This contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were treated as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to the unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, treatment of us as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the common units.

The discussion below assumes that we will be treated as a partnership for federal income tax purposes. See the discussion above of the opinion of Thompson & Knight L.L.P. that we will be treated as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders who have become limited partners of Crosstex Energy, L.P. will be treated as our partners for federal income tax purposes. Also:

- assignees who have executed and delivered transfer applications, and are awaiting admission as limited partners; and
- unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units,

will be treated as our partners for federal income tax purposes. Assignees of common units who are entitled to execute and deliver transfer applications and become entitled to direct the exercise of attendant rights, but who fail to execute and deliver transfer applications, may not be treated as one of our partners for federal income tax purposes. Furthermore, a purchaser or other transferee of common units who does not execute and deliver a transfer application may not receive some federal income tax information or reports furnished to record holders of common units unless the common units are held in a nominee or street name account and the nominee or broker has executed and delivered a transfer application for those common units.

A beneficial owner of common units whose common units have been transferred to a short seller to complete a short sale would appear to lose his status as one of our partners with respect to those common units for federal income tax purposes. Please read "—Tax Consequences of Unit Ownership—Treatment of short sales" beginning on page 125.

No portion of our income, gain, deductions or losses is reportable by a unitholder who is not one of our partners for federal income tax purposes, and any cash distributions received by a unitholder who is not one of our partners for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their own tax advisors with respect to the consequences of holding common units for federal income tax purposes.

The following assumes that a unitholder is treated as one of our partners.

Tax Consequences of Unit Ownership

Flow-through of taxable income. Each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions even if no cash distributions are received by him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution from us. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of distributions. Our distributions to a unitholder generally will not be taxable to him for federal income tax purposes to the extent of his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under "—Disposition of Common Units" below. Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, which are known as "nonrecourse liabilities," will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read "—Limitations on deductibility of losses" on page 124.

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities and result in a corresponding

deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture and substantially appreciated "inventory items," both as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, he will be treated as having been distributed his proportionate share of our Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of taxable income to distributions. We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through December 31, 2006, will be allocated an amount of federal taxable income for that period that will be 20% or less of the cash distributed with respect to that period. We anticipate that after the taxable year ending December 31, 2006, the ratio of allocable taxable income to cash distributions to the unitholders will increase. These estimates are based upon the assumption that gross income from operations will approximate the amount required to make the minimum quarterly distribution on all units and other assumptions with respect to capital expenditures, cash flow and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. In particular, our estimate is based upon our use of a seven year recovery period for our gathering systems and certain other property, which is consistent with decisions of the Courts of Appeals for the Sixth and Tenth Circuits on the issue. The IRS has stated that it will continue to litigate whether the recovery period is seven years or 15 years for taxpayers, such as us, for whom the appeal in any tax controversy would be to another Court of Appeals. The lower courts that have addressed the issue have not been consistent. A district court in Wyoming held that the recovery period for similar property is seven years, and the government agreed to dismiss the appeal of this issue because the appeal was to the Tenth Circuit. The Tax Court has held that the recovery period for similar property is 15 years. Legislation to resolve this dispute between the courts has been proposed by Congress. If passed, this legislation would establish a seven year recovery period for natural gas gathering lines.

If we were required to depreciate our gathering systems over a 15 year recovery period, then we estimate that a purchaser of common units in this offering who owns such common units through December 31, 2006, will be allocated an amount of federal taxable income for such period that will be no more than 20% of the cash distributed with respect to that period, and that after the taxable year ending December 31, 2006, the ratio of allocable taxable income to cash distributions to unitholders will increase. Further, our estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, these estimates may not prove to be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower, and any differences could be material and could materially affect the value of the common units.

Basis of common units. A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by distributions he receives from us, by his share of our losses, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder generally will have no share of our debt that is recourse to the general partner, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read "—Disposition of Common Units—Recognition of gain or loss" beginning on page 128.

Limitations on deductibility of losses. The deduction by a unitholder of his share of our losses will be limited to the tax basis in his common units and, in the case of an individual unitholder or a corporate unitholder, if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by five or fewer individuals or some tax-exempt organizations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause his at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable to the extent that his tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his common units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his common units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the common units for repayment. A unitholder's at risk amount will increase or decrease as the tax basis of the unitholder's common units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

The passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally corporate or partnership activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments in other publicly traded partnerships, or salary or active business income. Passive losses that are not deductible because they exceed a unitholder's share of our income may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions, including the at risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

Limitations on interest deductions. The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that the net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, a unitholder's share of our portfolio income will be treated as investment income.

Entity-level collections. If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or the general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the unitholder on whose behalf the payment was made. If the payment is made on behalf of a unitholder whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend the partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of common units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under the partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of a unitholder in which event the unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of income, gain, loss and deduction. In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among the general partner and the unitholders in accordance with their percentage interests in us. At any time that distributions are made to the common units in excess of distributions to the subordinated units, or incentive distributions are made to the general partner, gross income will be allocated to the recipients to the extent of these distributions. If we have a net loss for the entire year, that loss will be allocated first to the general partner and the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to the general partner. In order to allocate neither gain nor loss to our unitholders for 2002 (and to provide thereto K-1s which so report), we allocated our net loss for the portion of 2002 that was after the initial offering to our general partner. Thus, we will allocate to our general partner an equal amount of our net income for 2003 or a future period.

Certain items of our income, gain, loss and deduction will be allocated to account for the difference between the tax basis and fair market value of our property at the time of this offering. We will use the remedial method with respect to such differences with respect to some, but not all, of our assets, and we may use other methods with respect to some assets. The effect to a unitholder purchasing common units in this offering will, as to those assets in respect of which we use the remedial method, be essentially the same as if the tax basis of such assets was equal to their fair market value at the time of this offering, and the effect of allocations that are made under the traditional method will be essentially the same as if those assets had a tax basis that is less than fair market value. In addition, recapture income will be allocated to the extent possible to the unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by other unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner to eliminate the negative balance as quickly as possible.

Thompson & Knight L.L.P. is of the opinion that, with the exception of the issues described in "—Section 754 election" beginning on page 126 and "—Disposition of Common Units—Allocations between transferors and transferees" on page 129, the allocations in our partnership agreement will be given effect for federal income tax purposes in determining how our income, gain, loss or deduction will be allocated among the holders of our equity that is outstanding immediately after the offering that is made by this prospectus.

Treatment of short sales. A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, he

would no longer be a partner for tax purposes with respect to those common units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those common units would not be reportable by him;
- any cash distributions received by him on those common units would be fully taxable; and
- all of these distributions would appear to be ordinary income to him.

Thompson & Knight L.L.P. has not rendered an opinion regarding the treatment of a unitholder whose common units are loaned to a short seller; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing or loaning their common units. The IRS has announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please read "—Disposition of Common Units—Recognition of gain or loss" beginning on page 128.

Alternative minimum tax. Each unitholder will be required to take into account his share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. We do not expect to generate significant tax preference items or adjustments. Prospective unitholders are urged to consult with their tax advisors as to the impact of an investment in common units on their liability for the alternative minimum tax.

Tax rates. In general, the highest effective United States federal income tax rate for individuals for 2003 is 35% and the maximum United States federal income tax rate for net capital gains of an individual for 2003 is 15% if the asset disposed of was held for more than 12 months at the time of disposition.

Section 754 election. We made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election generally permits us to adjust a common unit purchaser's tax basis in our assets under Section 743(b) of the Internal Revenue Code to reflect his purchase price when he buys common units from a holder thereof. This election does not apply to a person who purchases common units directly from us.

Treasury regulations under Section 743 of the Internal Revenue Code require, if the remedial allocation method is adopted, that the portion of the Section 743(b) adjustment that eliminates the effect of any unamortized difference in "book" and tax basis of recovery property to the holder of such a common unit be depreciated over the remaining recovery period of that property, but Treasury Regulation Section 1.167(c)-1(a)(6) may require that any such difference in "book" and tax basis of other property be depreciated over a different period. In addition, the holder of a common unit (other than a common unit that is sold in this offering) may be entitled by reason of a Section 743(b) adjustment to amortization deductions in respect of property to which the traditional method of eliminating differences in "book" and tax basis applies but to which the holder of a common unit that is sold in this offering will not be entitled.

Under our partnership agreement, our general partner is authorized to take a position to preserve our ability to determine the tax attributes of a common unit from its date of purchase and the amount that is paid therefor even if that position is not consistent with the Treasury Regulations.

We intend to depreciate the portion of a Section 743(b) adjustment attributable to any unamortized difference between the "book" and tax basis of an asset in respect of which we use the remedial method in a manner that is consistent with the regulations under Section 743 of the Internal Revenue Code as to recovery property in respect of which the remedial allocation method is adopted. Such method is arguably inconsistent with Treasury Regulation Section 1.167(c)-l(a)(6), which is not

expected to directly apply to a material portion of our assets. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position which may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. In addition, if common units other than those that are sold in this offering are entitled to different treatment in respect of property as to which we are using the traditional method of eliminating differences in "book" and tax basis, we may also take a position that results in lower annual deductions to some or all of our unitholders than might otherwise be available. Counsel is unable to opine as to the validity of any position that is described in this paragraph because there is no clear applicable authority.

A Section 754 election is advantageous if the transferee's tax basis in his common units is higher than the common units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation deductions and his share of any gain on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his common units is lower than those common units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the common units may be affected either favorably or unfavorably by the election.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally amortizable over a longer period of time or under a less accelerated method than our tangible assets. The determinations we make may be successfully challenged by the IRS and the deductions resulting from them may be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of common units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting method and taxable year. We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his common units following the close of our taxable year but before the close of his taxable year will be required to include in income for his taxable year his share of more than one year of our income, gain, loss and deduction. Please read "—Disposition of Common Units—Allocations between transferors and transferees" on page 129.

Tax basis, depreciation and amortization. The tax basis of our assets is used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to this offering will be borne by the general partner, its affiliates and our other unitholders as of that time. Please read "—Tax Consequences of Unit Ownership—Allocation of income, gain, loss and deduction" on page 125.

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. Property

we acquire or construct in the future may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure, or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his units. Please read "—Tax Consequences of Unit Ownership—Allocation of income, gain, loss and deduction" on page 125 and "—Disposition of Common Units—Recognition of gain or loss" below.

The costs that we incur in selling our common units ("syndication expenses") must be capitalized and cannot be deducted by us currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which will be amortized by us over a period of 60 months, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and tax basis of our properties. The federal income tax consequences of the ownership and disposition of common units will depend in part on our estimates of the fair market values, and determinations of the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the fair market value estimates ourselves. These estimates of value and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates and determinations of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of gain or loss. Gain or loss will be recognized on a sale of common units equal to the difference between the amount realized and the unitholder's tax basis for the common units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of common units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than his tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in common units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of common units held more than 12 months will generally be taxed at a maximum rate of 15%. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture, other potential recapture items, or other "unrealized receivables" or to "inventory items" we own. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of common units. Capital losses may offset capital gains and no more

than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis common units to sell, but, under the regulations, may designate specific common units sold for purposes of determining the holding period of the common units sold. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of our common units. A unitholder considering the purchase of additional common units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the regulations.

The Internal Revenue Code treats a taxpayer as having sold a partnership interest, such as our units, in which gain would be recognized if it were actually sold at its fair market value, if the taxpayer or related persons enters into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property.

Allocations between transferors and transferees. In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of common units owned by each of them as of the opening of the applicable exchange on the first business day of the month. However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the first business day of the month in which that gain or loss is recognized. As a result, a unitholder transferring common units may be allocated income, gain, loss and deduction realized after the date of transfer.

The use of this method may not be permitted under existing Treasury Regulations. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferors and transferees as well as among unitholders whose interests vary during a taxable year to conform to a method permitted under future Treasury Regulations.

A unitholder who owns common units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification requirements. A purchaser of common units other than an individual who is a citizen of the United States and who purchases through a broker is required to notify us in writing of that purchase within 30 days after the purchase. We are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase may lead to the imposition of substantial penalties.

Constructive termination. We will be considered to have been "terminated" for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. A "termination" of us will result in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Tax-Exempt Organizations and Other Investors

Ownership of common units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations, other foreign persons and regulated investment companies or mutual funds raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to it.

A regulated investment company, or "mutual fund," is required to derive 90% or more of its gross income from interest, dividends and gains from the sale of stocks or securities or foreign currency or specified related sources. It is not anticipated that any significant amount of our gross income will include that type of income.

Non-resident aliens and foreign corporations, trusts or estates that own common units will be considered to be engaged in business in the United States because of the ownership of common units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, we will withhold at the highest effective tax rate applicable to individuals from cash distributions made quarterly to foreign unitholders. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8 BEN or applicable substitute form in order to obtain credit for the taxes withheld. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns common units will be treated as engaged in a United States trade or business, that corporation may be subject to the United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," which are effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling of the IRS, a foreign unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the sale or disposition of that unit to the extent that this gain is effectively connected with a United States trade or business of the foreign unitholder. Apart from the ruling, a foreign unitholder will not be taxed or subject to withholding upon the sale or disposition of a unit if he has owned less than 5% in value of the common units during the five-year period ending on the date of the disposition and if the common units are regularly traded on an established securities market at the time of the sale or disposition.

Administrative Matters

Information returns and audit procedures. We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which generally will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine his share of income, gain, loss and deduction. We cannot assure you that any of those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Any challenge by the IRS could negatively affect the value of the common units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. The partnership agreement names our general partner as our Tax Matters Partner.

The Tax Matters Partner has made and will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee reporting. Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;

- whether the beneficial owner is:

  (1) a person that is not a United States person;

  (2) a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

  (3) a tax-exempt entity;

- the amount and description of common units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on common units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the common units with the information furnished to us.

Registration as a tax shelter. The Internal Revenue Code requires that "tax shelters" be registered with the Secretary of the Treasury. Although we may not be a "tax shelter" for such purposes, we have registered as a "tax shelter" with the Secretary of the Treasury in light of the substantial penalties that might be imposed if registration is required and not undertaken. Our tax shelter registration number is 02337000008.

Issuance of this tax shelter registration number does not indicate that investment in us or the claimed tax benefits have been reviewed, examined or approved by the IRS.

A unitholder who sells or otherwise transfers a common unit in a later transaction must furnish the registration number to the transferee. The penalty for failure of the transferor of a unit to furnish the registration number to the transferee is $100 for each failure. A unitholder must disclose our tax shelter registration number on his tax return on which any deduction, loss or other benefit we generate is claimed or on which any of our income is included. A unitholder who fails to disclose the tax shelter registration number on Form 8271 to be attached to his return, without reasonable cause for that failure, will be subject to a $250 penalty for each failure. Any penalties discussed are not deductible for federal income tax purposes.

Accuracy-related penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

A substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 for most corporations). The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

- for which there is, or was, "substantial authority;" or
- as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

More stringent rules apply to "tax shelters," a term that in this context does not appear to include us. If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns to avoid liability for this penalty.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 200% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). If the valuation claimed on a return is 400% or more than the correct valuation, the penalty imposed increases to 40%.

State, Local, Foreign and Other Tax Consequences

In addition to federal income taxes, you will be subject to other taxes, including state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. We own property or do business in Texas, Oklahoma, Louisiana, New Mexico, Arkansas, Mississippi and Alabama. We may also own property or do business in other jurisdictions in the future. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and to pay income taxes in many of these jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. Some of the jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read "—Tax Consequences of Unit Ownership—Entity-level collections" on page 125. Based on current law and our estimate of our future operations, we anticipate that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of his investment in us. Accordingly, each prospective unitholder is urged to consult his tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as United States federal tax returns, that may be required of him. Thompson & Knight L.L.P. has not rendered an opinion on the state, local or foreign tax consequences of an investment in us.

INVESTMENT IN CROSSTEX ENERGY, L.P. BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA, and restrictions imposed by Section 4975 of the Internal Revenue Code. For these purposes, the term "employee benefit plan" includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization. Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA;
- whether in making the investment, that plan will satisfy the diversification requirements of Section 404(a)(l)(C) of ERISA; and
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return.

The person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibits employee benefit plans, and also IRAs that are not considered part of an employee benefit plan, from engaging in specified transactions involving "plan assets" with parties that are "parties in interest" under ERISA or "disqualified persons" under the Internal Revenue Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our general partner also would be a fiduciary of the plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed "plan assets" under some circumstances. Under these regulations, an entity's assets would not be considered to be "plan assets" if, among other things:

- the equity interests acquired by employee benefit plans are publicly offered securities; i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;

- the entity is an "operating company,"—i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority owned subsidiary or subsidiaries; or

- there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest, disregarding some interests held by the general partner, its affiliates, and some other persons, is held by the employee benefit plans referred to above, IRAs and other employee benefit plans not subject to ERISA, including governmental plans.

Our assets should not be considered "plan assets" under these regulations because it is expected that the investment will satisfy the requirements in the first bullet point above.

Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA and the Internal Revenue Code in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

UNDERWRITING

Subject to the terms and conditions of the underwriting agreement between us and the underwriters, the underwriters have agreed severally to purchase from us the following number of common units at the offering price less the underwriting discount set forth on the cover page of this prospectus.

Underwriters	Number of Common Units
A.G. Edwards & Sons, Inc.	562,500
RBC Dain Rauscher Inc.	562,500
Raymond James & Associates, Inc.	375,000
Total	1,500,000

The underwriting agreement provides that the obligations of the underwriters are subject to certain conditions and that the underwriters will purchase all such common units if any of the units are purchased. The underwriters are obligated to take and pay for all of the common units offered hereby, other than those covered by the over-allotment option described below, if any are taken.

The underwriters have advised us that they propose to offer the common units to the public at the offering price set forth on the cover page of this prospectus and to certain dealers at such price less a concession not in excess of $1.13 per unit. The underwriters may allow, and such dealers may re-allow, a concession not in excess of $0.10 per unit to certain other dealers. After the offering, the offering price and other selling terms may be changed by the underwriters, but any such changes will not affect the net proceeds to be received by us in the offering.

Pursuant to the underwriting agreement, we have granted to the underwriters an option, exercisable for 30 days after the date of this prospectus, to purchase up to 225,000 additional common units at the offering price, less the underwriting discount set forth on the cover page of this prospectus, solely to cover over-allotments.

To the extent the underwriters exercise such option, the underwriters will become obligated, subject to certain conditions, to purchase approximately the same percentage of such additional units as the number set forth next to such underwriter's name in the preceding table bears to the total number of units in the table, and we will be obligated, pursuant to the option, to sell such units to the underwriters.

Crosstex Energy, L.P., Crosstex Energy Holdings Inc., the general partner and the directors and executive officers of the general partner of our general partner have agreed that during the 90 days after the date of this prospectus, they will not, without the prior written consent of A.G. Edwards & Sons, Inc., directly or indirectly, offer for sale, contract to sell, sell, distribute, grant any option, right or warrant to purchase, pledge, hypothecate or otherwise dispose of any common units, any securities convertible into, or exercisable or exchangeable for, common units or any other rights to acquire such common units, other than (1) pursuant to employee benefit plans as in existence as of the date of this prospectus, (2) to affiliates or (3) in connection with accretive acquisitions of assets or businesses in which common units are issued as consideration; *provided, however,* any recipient of common units will furnish to A.G. Edwards & Sons, Inc. a letter agreeing to be bound by these provisions for the remainder of the 90-day period. The restrictions described in this paragraph also do not apply to the pledge of up to 100,000 common units by Crosstex Energy Holdings Inc. and the general partner pursuant to borrowings which are used by the general partner to make a capital contribution to us in order to maintain its 2% general partner interest in our partnership in connection with this offering. A.G. Edwards & Sons, Inc. may, in its sole discretion, allow any of these parties to offer for sale, contract to sell, sell, distribute, grant any option, right or warrant to purchase, pledge, hypothecate or

otherwise dispose of any common units, any securities convertible into, or exercisable or exchangeable for, common units or any other rights to acquire such common units prior to the expiration of such 90-day period in whole or in part at anytime without notice. A.G. Edwards & Sons, Inc. has informed us that in the event that consent to a waiver of these restrictions is requested by us or any other person, A.G. Edwards & Sons, Inc., in deciding whether to grant its consent, will consider the unitholder's reasons for requesting the release, the number of units for which the release is being requested, and market conditions at the time of the request for such release. However, A.G. Edwards & Sons, Inc. has informed us that as of the date of this prospectus there are no agreements between A.G. Edwards & Sons, Inc. and any party that would allow such party to transfer any common units, nor does it have any intention of releasing any of the common units subject to the lock-up agreements prior to the expiration of the lock-up period at this time.

The following table summarizes the discounts that Crosstex Energy, L.P. will pay to the underwriters in the offering. These amounts assume both no exercise and full exercise of the underwriters' option to purchase additional common units.

	No Exercise	Full Exercise
Per Unit	$ 1.888	$ 1.888
Total	$ 2,832,000	$ 3,256,800

We expect to incur expenses of approximately $1.0 million in connection with this offering.

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act.

Until the distribution of the common units is completed, rules of the SEC may limit the ability of the underwriters and certain selling group members to bid for and purchase the common units. As an exception to these rules, the underwriters are permitted to engage in certain transactions that stabilize, maintain or otherwise affect the price of the common units.

In connection with this offering, the underwriters may engage in stabilizing transactions, over-allotment transactions, syndicate covering transactions and penalty bids in accordance with Regulation M under the Securities Exchange Act of 1934.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.
- Over-allotment transactions involve sales by the underwriters of the common units in excess of the number of units the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of units over-allotted by the underwriters is not greater than the number of units they may purchase in the over-allotment option. In a naked short position, the number of units involved is greater than the number of units in the over-allotment option. The underwriters may close out any short position by either exercising their over-allotment option and/or purchasing common units in the open market.
- Syndicate covering transactions involve purchases of the common units in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of the common units to close out the short position, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through the over-allotment option. If the underwriters sell more common units than could be covered by the over-allotment option, a naked short position, the position can only be closed out by buying common units in the open market. A naked short position is more likely to be created if the underwriters are

concerned that there could be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering.

- Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common units originally sold by the syndicate member are purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

Similar to other purchase transactions, the underwriters' purchases to cover the syndicate short sales may have the effect of raising or maintaining the market price of the common units or preventing or retarding a decline in the market price of the common units. As a result, the price of the common units may be higher than the price that might otherwise exist in the open market.

The underwriters will deliver a prospectus to all purchasers of common units in the short sales. The purchasers of common units in short sales are entitled to the same remedies under the federal securities laws as any other purchaser of common units covered by this prospectus.

The underwriters are not obligated to engage in any of the transactions described above. If they do engage in any of these transactions, they may discontinue them at any time.

Neither Crosstex Energy, L.P. nor the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common units. In addition, neither Crosstex Energy, L.P. nor the underwriters make any representation that the underwriters will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

Because the National Association for Securities Dealers, Inc. views the common units offered hereby as interests in a direct participation program, the offering is being made in compliance with Rule 2810 of the NASD's Conduct Rules. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

No sales to accounts of which the underwriter exercises discretionary authority may be made without the prior written approval of the customer.

An affiliate of RBC Dain Rauscher Inc. is a lender under our operating partnership's bank credit facility. The proceeds of this offering will be used to repay a portion of the outstanding indebtedness under our operating partnership's bank credit facility. A.G. Edwards & Sons, Inc. has performed various financial advisory services for us and our predecessor for which it received customary compensation. A.G. Edwards & Sons, Inc., RBC Dain Rauscher Inc. and Raymond James & Associates, Inc. were underwriters in our initial public offering that closed on December 17, 2002. The underwriters may, from time to time, engage in transactions with and perform services for us in the ordinary course of their business.

VALIDITY OF THE COMMON UNITS

The validity of the common units will be passed upon for us by Thompson & Knight, L.L.P., Dallas, Texas. Certain legal matters in connection with the common units offered hereby will be passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

The consolidated financial statements of Crosstex Energy, L.P. as of December 31, 2001 and 2002 and for the four months ended April 30, 2000 (Predecessor), the eight months ended December 31, 2000 and the years ended December 31, 2001 and 2002, and the balance sheet of Crosstex Energy G.P., L.P. as of December 31, 2002 have been included herein and in the registration statement in reliance upon the reports of KPMG LLP, independent accountants, appearing elsewhere herein, and upon the authority of said firm as experts in accounting and auditing. The audit report covering the December 31, 2001 financial statements of Crosstex Energy, L.P. refers to a change in the method of accounting for derivatives. The audit report covering the December 31, 2002 financial statements of Crosstex Energy, L.P. refers to a change in the method of amortizing goodwill.

The statement of revenues and direct operating expenses of the Certain Mid-Stream Assets of Duke Energy Field Services, L.P. for the year ended December 31, 2002 included in this prospectus has been audited by Deloitte & Touche LLP, independent auditors, as stated in their report appearing herein (which report expresses an unqualified opinion and includes an explanatory paragraph emphasizing that the statement was prepared for the purpose of complying with the rules and regulations of the Securities and Exchange Commission and is not intended to be a complete presentation of the revenues and direct operating expenses of the assets, as defined in the purchase and sale agreement between Duke Energy Field Services, L.P. and Crosstex Energy, L.P. dated April 29, 2003), and has been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the Securities and Exchange Commission a registration statement on Form S-l regarding the common units. This prospectus does not contain all of the information found in the registration statement. For further information regarding us and the common units offered by this prospectus, you may desire to review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at Room 1024, 450 Fifth Street, N.W., Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at Room 1024, Judiciary Plaza, 450 Fifth Street, N.W., Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at l-800-SEC-0330.

The SEC maintains a web site on the Internet at http://www.sec.gov. Our registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC's website.

We intend to furnish our unitholders annual reports containing our audited financial statements and furnish or make available quarterly reports containing our unaudited interim financial information for the first three fiscal quarters of each of our fiscal years.

FORWARD-LOOKING STATEMENTS

Statements included in this prospectus 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 the information set forth in Appendix E, are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "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 and our representatives may from time to time make other oral or written statements which are also forward-looking statements.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number or risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Risk Factors" beginning on page 16, and elsewhere in this prospectus.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. Before you invest, you should be aware that the occurrence of any of the events described in "Risk Factors" beginning on page 16 and elsewhere in this prospectus could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common units could decline, and you could lose all or part of your investment.

INDEX TO FINANCIAL STATEMENTS

Crosstex Energy, L.P.
Unaudited Pro Forma Financial Statements

Introduction

The following are our unaudited pro forma financial statements as of June 30, 2003, and for the year ended December 31, 2002 and the six months ended June 30, 2003. The unaudited pro forma condensed consolidated balance sheet assumes that the issuance of $10.0 million of senior secured notes and this offering and related transactions occurred as of June 30, 2003, and the unaudited pro forma consolidated statements of operations assumes that the acquisition from Duke Energy Field Services, L.P., the senior secured note offerings, this offering and related transactions and our initial public offering occurred on January 1, 2002. These transaction adjustments are presented in the notes to the unaudited pro forma financial statements. The unaudited pro forma financial statements and accompanying notes should be read together with the financial statements and related notes included elsewhere in the prospectus.

The pro forma financial statements reflect the following transactions:

- our acquisition of the DEFS assets for $67.3 million which closed on June 30, 2003;
- borrowings under our new credit facility in order to finance the acquisition from DEFS;
- borrowings under our new senior notes facility in order to repay borrowings under our new credit facility;
- our offering of 1,500,000 common units at an offering price of $35.97 per common unit resulting in aggregate gross proceeds to us of $54.0 million;
- the payment of underwriting fees and commissions, and other fees and expenses associated with the offering, expected to be approximately $3.8 million; and
- for the pro forma statement of operations for the year ended December 31, 2002, our initial public offering of 2,300,000 common units at an offering price of $20.00 per common unit and the formation transactions related to our partnership.

The pro forma balance sheet and the pro forma statements of operations were derived by adjusting the historical financial statements of Crosstex Energy, L.P. The adjustments are based on currently available information and, therefore, the actual adjustments may differ from the pro forma adjustments. However, management believes that the adjustments provide a reasonable basis for presenting the significant effects of the acquisition from DEFS and the other transactions. The unaudited pro forma financial statements do not purport to present the financial position or results of operations of Crosstex Energy, L.P. had the acquisition from DEFS or the other transactions actually been completed as of the dates indicated. Moreover, the statements do not project the financial position or results of operations of Crosstex Energy, L.P. for any future date or period.

Crosstex Energy, L.P.

Unaudited Pro Forma Consolidated Balance Sheet

June 30, 2003

(In thousands, except unit data)

	Crosstex Energy, L.P.	Adjustments	Pro Forma	Offering Adjustments	Pro forma As Adjusted
Assets					
Current assets:					
Cash and cash equivalents	$ 1,626	$ —	$ 1,626	$ 53,955 (b) (3,833)(c) 1,101 (d) (51,223)(e)	$ 1,626
Accounts receivable	142,993		142,993		142,993
Assets from risk management activities	2,578		2,578		2,578
Prepaid expenses and other	2,525		2,525		2,525
Total current assets	149,722	—	149,722	—	149,722
Property and equipment, net	188,986		188,986		188,986
Assets from risk management activities	1		1		1
Intangible assets, net	5,847		5,847		5,847
Goodwill, net	4,873		4,873		4,873

Investment in limited partnerships	1,113		1,113		1,113
Other assets, net	2,023		2,023		2,023
Total assets	$ 352,565	$ —	$ 352,565	$ —	$ 352,565
Liabilities and Partners' Equity					
Current liabilities:					
Accounts payable and accrued gas purchases	$ 151,785	$ —	$ 151,785	$ —	$ 151,785
Accrued imbalances payable	268		268		268
Liabilities from risk management activities	4,605		4,605		4,605
Current portion of long-term debt	50		50		50
Other current liabilities	4,033		4,033		4,033
Total currrent liabilities	160,741	—	160,741	—	160,741
Long-term debt	98,700	10,000 (a) (10,000)(a)	98,700	(51,223)(e)	47,477
Liabilities from risk management activities	20		20		20
Liability from interest rate swap	323		323		323
Partners' equity:					
Common unitholders	59,126		59,126	53,955 (b) (3,833)(c)	109,248
Subordinated unitholders	34,669		34,669		34,669
General partner interest	1,163		1,163	1,101 (d)	2,264
Other comprehensive income (loss)	(2,177)		(2,177)		(2,177)
Total partners' equity	92,781		92,781	51,223	144,004
Total liabilities and partners' equity	$ 352,565	$ —	$ 352,565	$ —	$ 352,565

See accompanying notes to unaudited pro forma financial statements.

Crosstex Energy, L.P.

Unaudited Pro Forma Consolidated Statement of Operations

Six Months Ended June 30, 2003

(In thousands, except per unit data)

	Crosstex Historical	DEFS Assets	Adjustments	Pro Forma	Offering Adjustments	Pro Forma As Adjusted
Revenues:						
Midstream	$ 469,345	$ 106,322	$ —	$ 575,667	$ —	$ 575,667
Treating	10,477			10,477		10,477
Total revenues	479,822	106,322	—	586,144	—	586,144
Operating costs and expenses:						
Midstream purchased gas	451,479	97,838		549,317		549,317
Treating purchased gas	4,451			4,451		4,451
Operating expenses	6,545	3,098		9,643		9,643
General and administrative	3,391			3,391		3,391
Stock based compensation	3,072			3,072		3,072
Impairments	—			—		—
(Profit) loss on energy trading	(845)			(845)		(845)
Depreciation and amortization	5,046	1,924	369(f)	7,339		7,339
Total operating costs and expenses	473,139	102,860	369	576,368	—	576,368

	Crosstex Historical	DEFS Assets	Adjustments	Pro Forma	Offering Adjustments	Pro Forma As Adjusted
Operating income (loss)	6,683	3,462	(369)	9,776	—	9,776
Other income (expense):						
Interest expense, net	(875)		(2,103)(g)	(2,978)	1,150(h)	(1,828)
Other income	(1)			(1)		(1)
Total other income (expense)	(876)	—	(2,103)	(2,979)	1,150	(1,829)
Net income	$ 5,807	$ 3,462	$ (2,472)	$ 6,797	$ 1,150	$ 7,947
General partner share of net income	172			191		225
Limited partners share of net income	$ 5,635			$ 6,606		$ 7,722
Net income per limited partners' unit:						
Basic	$ 0.77			$ 0.91		$ 0.88
Diluted	$ 0.77			$ 0.90		$ 0.87
Weighted-average limited partners' units outstanding						
Basic	7,300			7,300		8,800(i)
Diluted	7,366			7,366		8,866(i)

See accompanying notes to unaudited pro forma financial statements.

Crosstex Energy, L.P.

Unaudited Pro Forma Consolidated Statement of Operations

Year Ended December 31, 2002

(In thousands, except per unit data)

	Crosstex Historical	DEFS Assets	Adjustments	Pro Forma	Offering Adjustments	Pro Forma As Adjusted
Revenues:						
Midstream	$ 437,676	$ 137,255	$ (174)(j)	$ 574,757	$ —	$ 574,757
Treating	14,817			14,817		14,817
Total revenues	452,493	137,255	(174)	589,574	—	589,574
Operating costs and expenses:						
Midstream purchased gas	413,982	120,966	(109)(j)	534,839		534,839
Treating purchased gas	5,767			5,767		5,767
Operating expenses	10,468	5,282	(89)(j)	15,661		15,661
General and administrative	8,454		(2,454)(k)	6,000		6,000
Stock based compensation	41			41		41
Impairments	4,175	6,900	(6,900)(f)	4,175		4,175
(Profit) loss on energy trading	(2,703)			(2,703)		(2,703)
Depreciation and amortization	7,745	4,277	(150)(j) 308 (f)	12,180		12,180
Total operating costs and expenses	447,929	137,425	(9,394)	575,960	—	575,960
Operating income (loss)	4,564	(170)	9,220	13,614		13,614
Other income (expense):						
Interest expense, net	(2,717)		(4,420)(g) 1,423 (l)	(5,714)	2,433(h)	(3,281)

Other income	155			155		155
Total other income (expense)	(2,562)	—	(2,997)	(5,559)	2,433	(3,126)
Net income	$ 2,002	$ (170)	$ 6,223	$ 8,055	$ 2,433	$ 10,488
General partner share of net income	6			161		210
Limited partners share of net income	$ 314			$ 7,894		$ 10,278
Net income per limited partners' unit:						
Basic	$ 0.04			$ 1.08		$ 1.17
Diluted	$ 0.04			$ 1.08		$ 1.17
Weighted-average limited partners units outstanding:						
Basic	7,300			7,300		8,800 (i)
Diluted	7,310			7,310		8,810 (i)

See accompanying notes to unaudited pro forma financial statements.

Crosstex Energy, L.P.

Notes to Unaudited Pro Forma Financial Statements

Offering and Transactions

The pro forma financial statements reflect the following transactions:

- borrowings under our new credit facility in order to finance the acquisition from DEFS;
- borrowings under our new senior notes facility in order to repay borrowings under our new credit facility;
- our offering of 1,500,000 common units at an offering price of $35.97 per common unit resulting in aggregate gross proceeds to us of $54.0 million;
- the payment of underwriting fees and commissions, and other fees and expenses associated with the offering, expected to be approximately $3.8 million; and
- for the pro forma statement of operations for the year ended December 31, 2002, our initial public offering of 2,300,000 common units at an offering price of $20.00 per common unit and the formation transactions related to our partnership.

Pro Forma Adjustments

(a) Reflects the proceeds to us from the issuance of $10.0 million senior secured notes under the master shelf agreement and the use of these proceeds to reduce our borrowings under the bank credit facility.

(b) Reflects the proceeds to us of $54.0 million from the issuance and sale of 1,500,000 common units at an offering price of $35.97 per common unit.

(c) Reflects the payment of underwriters' discounts and commissions and estimated offering expenses of $3.8 million. The underwriters' discounts and commissions and offering expenses will be allocated to the common units.

(d) Reflects the contribution of $1.1 million from our general partner in order to maintain its 2% interest.

(e) Represents the payment of $51.2 million under our revolving credit facility from proceeds of the offering and our general partner's contribution, which will reduce our long-term debt to $40.0 million outstanding under our senior notes facility, $6.8 million under our bank credit facility and $0.7 million of other indebtedness.

(f) Reflects the additional depreciation and amortization expense from the acquisition of the assets from DEFS. Pro forma depreciation and amortization expense was based on estimated useful lives of 15 years for the acquired assets and seven years for the intangible assets. Due to our new carrying value of the DEFS assets, historical depreciation expense and impairment expense on the DEFS assets have been eliminated in these pro forma statements.

(g) Reflects increase of interest expense resulting from the borrowings under our revolving credit facility of $28.0 million and senior notes facility of $40.0 million. The interest rates used to determine the pro forma adjustment for the borrowings under the revolving credit facility were based on our weighted-average borrowing rates of 4.49% and 4.75% for the six months ended June 30, 2003 and the year ended December 31, 2002, respectively. The interest rate used to determine the pro forma adjustment for the borrowings under the senior notes facility is the weighted-average fixed rate of 6.93% on the senior notes that have been issued.

(h) Reflects reduction of interest expense resulting from repayment of the $51.2 million of borrowings under our bank credit facility with proceeds from this offering and the capital contribution of our general partner. The interest rates used to determine the pro forma adjustment for the borrowings under the revolving credit facility were based on our weighted-average borrowing rates of 4.49% and 4.75% for the six months ended June 30, 2003 and the year ended December 31, 2002, respectively.

(i) The weighted-average limited partners' units outstanding used in the income per unit calculation includes the limited partners' common and subordinated units and excludes the general partner interest. The weighted-average limited partners' units outstanding have been adjusted to reflect the common units and subordinated units issued in connection with our initial public offering as if these units have been outstanding since January 1, 2002.

(j) The Jonesville gas plant owned by our predecessor was not contributed to us subsequent to our initial public offering. This adjustment reflects the elimination of the results on operations from the Jonesville gas plant, including depreciation and amortization and impairment, which was not contributed to us.

(k) Reflects the elimination of general and administrative expense to the extent our actual expenses exceed the $6.0 million reimbursement ($1.5 million per quarter) for the twelve month period ending in December 2003. Had the cap not been in place for the six months ended June 30, 2003, our general and administrative expenses would have been approximately $4.6 million. Our general partner will be reimbursed for expenses incurred on our behalf. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us. For the twelve month period ending in December 2003, this reimbursement will be limited to $6.0 million. This reimbursement cap will not apply to the cost of any third party legal, accounting or advisory services received, or direct expenses of management incurred, in connection with acquisition or business development opportunities evaluated on behalf of the partnership. In connection with our acquisition of the DEFS assets, we estimate additional general and administrative personnel will be added at an estimated annual cost of approximately $0.9 million. The DEFS acquisition will not change the $6.0 million cap for general and administrative expense for the twelve month period ending in December 2003.

(l) For the year ended December 31, 2002, the increase in interest expense in the statement of operations is partially offset by a reduction of interest expense resulting from the repayment of $33.0 million of borrowings under the bank credit facility with net proceeds from the initial public offering. The interest rate used to determine the pro forma adjustment was based on our predecessor's weighted-average borrowing rate of 4.48% for the period January 1, 2002 through December 16, 2002.

Pro Forma Net Income Per Unit

Pro forma net income per limited partners' unit for the year ended December 31, 2002 is determined by dividing the pro forma net income that would have been allocated to the holders of the common units and subordinated units, which is 98% of pro forma net income, by the number of common units and subordinated units expected to be outstanding at the close of the offering. For purposes of this calculation, the number of common units and subordinated units outstanding of 8,800,000 was assumed to have been outstanding since January 1, 2002. Pursuant to the partnership agreement, to the extent that the quarterly distribution exceeds certain thresholds, the general partner

is entitled to certain incentive distributions which will result in less income proportionately being allocated to the holders of the common units and subordinated units. The pro forma net income per unit for the six months ended June 30, 2003 reflects the incentive distribution to the general partner due to the distribution for the second quarter being $0.55.

Description of Equity Interest

The common units and the subordinated units represent limited partner interests in us. The holders of the units are entitled to participate in partnership distributions and exercise the rights and privileges available to limited partners under our partnership agreement.

The common units will have the right to receive a minimum quarterly distribution of $0.50 per unit, plus any arrearages on the common units, before any distribution is made to the holders of the subordinated units. In addition, if the general partner and its affiliates own more than 80% of the aggregate ownership of common and subordinated units, the general partner will have the right to call the common units at a price that approximates fair market value.

The subordinated units generally receive quarterly cash distributions only when the common units have received a minimum quarterly distribution of $0.50 per unit for each quarter since the commencement of operations. Subordinated units will convert into common units on a one-for-one basis when the subordination period ends. The subordination period will end when we meet financial tests specified in the partnership agreement but generally cannot end before December 31, 2007.

The general partner interest is entitled to at least 2% of all distributions made by us. In addition, the general partner holds incentive distribution rights, which allow the general partner to receive a higher percentage of quarterly distributions of Available Cash from Operating Surplus after the minimum distributions have been achieved, and as additional target levels are met. The higher percentages range from 15% up to 50%. The pro forma financial statements assume that no incentive distributions were made to the general partner, other than actual incentive distributions earned. In subsequent periods, we will apply the hypothetical liquidation at book value method in allocating income to the various partnership interests.

Independent Auditors' Report

The Partners
Crosstex Energy, L.P.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, L.P., a Delaware limited partnership and successor to Crosstex Energy Services, Ltd.

(the Partnership), and subsidiaries as of December 31, 2001 and 2002 and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for the four months ended April 30, 2000 (Predecessor), the eight months ended December 31, 2000 and the years ended December 31, 2001 and 2002. The financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Crosstex Energy, L.P. and subsidiaries as of December 31, 2001 and 2002, and the consolidated results of their operations, comprehensive income, and their cash flows for the four months ended April 30, 2000 (Predecessor), the eight months ended December 31, 2000, and the years ended December 31, 2001 and 2002, and in conformity with accounting principles generally accepted in the United States of America.

As explained in note 2 to the consolidated financial statements, effective January 1, 2001, the Partnership changed its method of accounting for derivatives. Also, as explained in note 2, effective January 1, 2002, the Partnership changed its method of amortizing goodwill.

KPMG LLP

Dallas, Texas
February 7, 2003

CROSSTEX ENERGY, L.P.

(Successor to Crosstex Energy Services, Ltd.)

Consolidated Balance Sheets

December 31, 2001 and 2002 and June 30, 2003

(In thousands)

Assets	December 31, 2001	December 31, 2002	June 30, 2003 (unaudited)
Current assets:			
Cash and cash equivalents	$ 352	$ 1,308	$ 1,626
Accounts receivable:			
Trade	58,222	104,802	140,916
Imbalances	117	79	—
Related party	418	—	844
Other	192	637	676
Notes receivable	—	—	557
Assets from risk management activities	3,361	2,947	2,578
Prepaid expenses and other	1,865	1,225	2,525
Total current assets	64,527	110,998	149,722
Property and equipment:			
Transmission assets	33,559	50,391	90,553
Gathering systems	12,541	22,624	25,443
Gas plants	37,373	39,475	75,851
Other property and equipment	2,692	2,754	3,052
Construction in process	5,092	6,935	10,871
Total property and equipment	91,257	122,179	205,770
Accumulated depreciation	(6,306)	(12,231)	(16,784)
Total property and equipment, net	84,951	109,948	188,986
Account receivable from Enron (net of allowance of $5,776 in 2001)	2,467	—	—
Assets from risk management activities	117	155	1
Intangible assets, net	9,678	5,340	5,847
Goodwill, net	4,873	4,873	4,873
Investment in limited partnerships	534	346	1,113
Other assets, net	1,229	778	2,023
Total assets	$ 168,376	$ 232,438	$ 352,565

Liabilities and Partners' Equity			
Current liabilities:			
Accounts payable and accrued gas purchases	$ 56,092	$ 110,793	$ 151,785
Accrued imbalances payable	422	149	268
Liabilities from risk management activities	7,565	4,006	4,605
Current portion of long-term debt	—	50	50
Other current liabilities	2,702	4,672	4,033
Total current liabilities	66,781	119,670	160,741
Long-term debt	60,000	22,500	98,700
Liabilities from risk management activities	440	271	20
Liability from interest rate swap	—	181	323
Partners' equity:			
Predecessor partners' equity	41,013	—	—
Common unitholders (2,633,000 units issued and outstanding at December 31, 2002 and June 30, 2003)	—	58,147	59,126
Subordinated unitholders (4,667,000 units issued and outstanding at December 31, 2002 and June 30, 2003)	—	31,829	34,669
General partner interest (2% interest with 149,000 equivalent units outstanding at December 31, 2002 and June 30, 2003)	—	1,016	1,163
Other comprehensive income (loss)	142	(1,176)	(2,177)
Total partners' equity	41,155	89,816	92,781
Total liabilities and partners' equity	$ 168,376	$ 232,438	$ 352,565

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

(Successor to Crosstex Energy Services, Ltd.)

Consolidated Statements of Operations

(In thousands)

	(Predecessor) Four Months Ended April 30, 2000	Eight Months Ended December 31, 2000	Years Ended December 31, 2001	Years Ended December 31, 2002	Six Months Ended June 30, 2002	Six Months Ended June 30, 2003
					(unaudited)	
Revenues:						
Midstream	$ 3,591	$ 88,008	$ 362,673	$ 437,676	$ 200,595	$ 469,345
Treating	5,947	17,392	24,353	14,817	6,878	10,477
Total revenues	9,538	105,400	387,026	452,493	207,473	479,822
Operating costs and expenses:						
Midstream purchased gas	2,746	83,672	344,755	413,982	189,675	451,479
Treating purchased gas	4,731	14,876	18,078	5,767	2,599	4,451
Operating expenses	544	1,796	7,430	10,468	5,050	6,545
General and administrative	810	2,010	5,914	8,454	4,206	3,391
Stock based compensation	8,802	—	—	41	—	3,072
Impairments	—	—	2,873	4,175	3,150	—
(Profit) loss on energy trading contracts	(638)	(1,253)	3,714	(2,703)	(2,754)	(845)
Depreciation and amortization	522	2,261	6,101	7,745	3,884	5,046
Total operating costs and expenses	17,517	103,362	388,865	447,929	205,810	473,139
Operating income (loss)	(7,979)	2,038	(1,839)	4,564	1,663	6,683
Other income (expense):						
Interest expense, net	(79)	(530)	(2,253)	(2,717)	(1,696)	(875)
Other income	381	115	174	155	5	(1)
Total other income (expense)	302	(415)	(2,079)	(2,562)	(1,691)	(876)

Net income (loss)	$ (7,677)	$ 1,623	$ (3,918)	$ 2,002	$ (28)	$ 5,807

	Year Ended December 31, 2002	Six Months Ended June 30, 2003
Allocation of 2002 net income:		
Net income for the period from January, 1, 2002 to December 16, 2002	$ 1,682	
Net income for the period from December 17, 2002 to December 31, 2002	320	
Net income	$ 2,002	$ 5,807
General partner interest in net income for the period from December 17, 2002 to December 31, 2002, and for the six months ended June 30, 2003, respectively	$ 6	$ 172
Limited partners' interest in net income for the period from December 17, 2002 to December 31, 2002, and for the six months ended June 30, 2003, respectively	$ 314	$ 5,635
Net income per limited partners' unit:		
Basic and diluted	$ 0.04	$ 0.77
Weighted-average limited partners' units outstanding:		
Basic	7,300	7,300
Diluted	7,310	7,366

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

(Successor to Crosstex Energy Services, Ltd.)

Consolidated Statements of Changes in Partners' Equity

(In thousands)

	Total
Balance, December 31, 1999	$ 3,242
Capital contributions	45
Equity based competition	7,999
Net loss	(7,677)
Balance, April 30, 2000 (Predecessor)	$ 3,609

	Crosstex Energy Services, Ltd. Partners' Equity	Crosstex Energy, L.P.				
		Common Units	Subordinated Units	General Partner Interest	Other Comprehensive Income	Total
Balance, May 5, 2000	$ —	$ —	$ —	$ —	$ —	$ —
Contributions of assets and liabilities predecessor	21,903	—	—	—	—	21,903
Capital contributions	16,828	—	—	—	—	16,828
Net income	1,623	—	—	—	—	1,623
Balance, December 31, 2000	40,354	—	—	—	—	40,354
Capital contributions	5,019	—	—	—	—	5,019
Distributions	(442)	—	—	—	—	(442)
Net loss	(3,918)	—	—	—	—	(3,918)
Cumulative adjustment from adoption of accounting standard	—	—	—	—	(1,006)	(1,006)
Hedging gains or losses reclassified to earnings	—	—	—	—	1,006	1,006
Adjustment in fair value of derivatives	—	—	—	—	142	142
Balance, December 31, 2001	41,013	—	—	—	142	41,155
Assets not contributed to Crosstex Energy, L.P.	(3,754)	—	—	—	—	(3,754)
Capital contributions	14,000	—	—	—	—	14,000
Stock based compensation	41	—	—	—	—	41
Net income from January 1, 2002 through December 16, 2002	1,682	—	—	—	—	1,682
Distributions	(2,500)	—	—	—	—	(2,500)
Transfer of equity in accordance with initial public offering	(50,482)	17,844	31,628	1,010	—	—
Net proceeds from the initial public offering	—	40,190	—	—	—	40,190
Net income from December 17, 2002 through December 31, 2002	—	113	201	6	—	320
Hedging gains or losses reclassified to earnings	—	—	—	—	(178)	(178)
Adjustment in fair value of derivatives	—	—	—	—	(1,140)	(1,140)
Balance, December 31, 2002	—	58,147	31,829	1,016	(1,176)	89,816
Offering costs	—	(622)	—	—	—	(622)
Stock based compensation	—	1,086	1,925	61	—	3,072
Distributions		(1,517)	(2,688)	(86)		(4,291)
Net income	—	2,032	3,603	172	—	5,807
Hedging gains or losses reclassified to earnings	—	—	—	—	952	952
Adjustment in fair value of derivatives	—	—	—	—	(1,953)	(1,953)

Balance, June 30, 2003	$ —	$ 59,126	$ 34,669	$ 1,163	$ (2,177)	$ 92,781

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

(Successor to Crosstex Energy Services, Ltd.)

Consolidated Statements of Comprehensive Income

December 31, 2001 and 2002 and June 30, 2003

(In thousands)

	December 31,		June 30, 2003
	2001	**2002**	**(unaudited)**
Net (loss) income	$ (3,918)	$ 2,002	$ 5,807
Cumulative adjustment from adoption of accounting standard	(1,006)	—	—
Hedging gains or losses reclassified to earnings	1,006	(178)	952
Adjustment in fair value of derivatives	142	(1,140)	(1,953)
Comprehensive income (loss)	$ (3,776)	$ 684	$ 4,806

See accompanying notes to consolidated financial statements

CROSSTEX ENERGY, L.P.

(Successor to Crosstex Energy Services, Ltd.)

Consolidated Statements of Cash Flows

(In thousands)

	(Predecessor) Four Months Ended April 30, 2000	Eight Months Ended December 31, 2000	Years Ended December 31,		Six Months Ended June 30,	
			2001	**2002**	**2002**	**2003**
					(unaudited)	
Cash flows from operating activities:						
Net income (loss)	$ (7,677)	$ 1,623	$ (3,918)	$ 2,002	$ (28)	$ 5,807
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:						
Depreciation, depletion, and amortization	522	2,261	6,101	7,745	3,884	5,046
Impairments	—	—	2,873	4,175	3,150	—
(Income) loss on investment in affiliated partnerships	(15)	(48)	(35)	41	19	(121)
Noncash stock based compensation	7,999	—	—	41	—	3,072
Loss on sale of assets	—	—	—	—	—	—
Changes in assets and liabilities:						
Accounts receivable	(994)	(83,668)	47,565	(46,544)	(25,908)	(36,917)
Prepaid expenses	(328)	108	(1,566)	178	(155)	(1,300)
Accounts payable, accrued gas purchases, and other accrued liabilities	8,129	87,442	(63,115)	54,427	50,095	41,111
Risk management activities	—	(47)	4,573	(4,669)	(3,985)	(131)
Other	(256)	70	(804)	2,560	12	(1,426)
Net cash provided by (used in) operating activities	7,380	7,741	(8,326)	19,956	27,084	15,141

Cash flows from investing activities:						
Additions to property and equipment	(3,026)	(4,667)	(22,685)	(14,545)	(5,975)	(17,267)
Asset purchases	—	(21,133)	(30,003)	(18,785)	(4,430)	(67,325)
Proceeds from disposition of assets	100	—	—	—	—	—
Investment in affiliated partnerships	—	—	—	—	—	(766)
Distributions from (investments in) affiliated partnerships	77	157	153	90	68	120
Net cash used in investing activities	(2,849)	(25,643)	(52,535)	(33,240)	(10,337)	(85,238)
Cash flows from financing activities:						
Proceeds from bank borrowings	7,000	51,950	267,131	384,050	186,300	236,600
Payments on bank borrowings	(6,847)	(36,950)	(229,150)	(421,500)	(203,000)	(160,400)
Predecessor cash	—	4,729	—	—	—	(872)
Distribution to partners	—	—	(442)	(2,500)	—	(4,291)
Net proceeds from initial public offering	—	—	—	40,190	—	—
Contribution from partners	45	16,828	5,019	14,000	14,000	(622)
Net cash provided by (used in) financing activities	198	36,557	42,558	14,240	(2,700)	70,415
Net increase (decrease) in cash and cash equivalents	4,729	18,655	(18,303)	956	14,047	318
Cash and cash equivalents, beginning of period	—	—	18,655	352	352	1,308
Cash and cash equivalents, end of period	$ 4,729	$ 18,655	$ 352	$ 1,308	$ 14,399	$ 1,626
Cash paid for interest	$ 144	$ 507	$ 2,720	$ 2,558	$ 1,466	$ 753
Noncash transactions—stock based compensation	7,999	—	—	41	—	3,072
Contributions of assets and liabilities of predecessor	—	21,903	—	—	—	—
Assets not contributed to Crosstex Energy, L.P.	—	—	—	3,754	—	—

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

(Successor to Crosstex Energy Services, Ltd.)

Notes to Consolidated Financial Statements

December 31, 2001 and 2002

(unaudited with respect to June 30, 2002 and 2003)

(1) Organization and Summary of Significant Agreements

(a) Description of Business

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

(b) Initial Public Offering

On December 17, 2002, the Partnership completed an initial public offering of common units representing limited partner interests in the Partnership. Prior to its initial public offering, the Partnership was an indirect wholly owned subsidiary of Crosstex Energy Holdings Inc. (Crosstex Holdings). Crosstex Holdings conveyed to the Partnership its indirect wholly owned ownership interest in Crosstex Energy Services, Ltd. (CES) in exchange for (i) a 2% general partner interest (including certain Incentive Distribution Rights) in the Partnership, (ii) 333,000 common units and (iii) 4,667,000 subordinated units of the Partnership. Prior to the conveyance of CES to the Partnership, CES distributed certain assets to Crosstex Holdings including (i) the Jonesville and Clarkson gas plants, (ii) the Enron receivable and related derivative positions, and (iii) the right to receive a cash distribution of $2.5 million.

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

(c) Organization of Crosstex Energy Services, Ltd.

Crosstex Energy Services, Ltd. (the Predecessor), a Texas limited partnership was formed on December 19, 1996, to engage in the gathering, transmission, treating, processing, and marketing of natural gas. Upon consummation of the initial public offering, the Predecessor was merged into and became Crosstex Energy Services, L.P. (CES, L.P.).

Effective May 5, 2000, Crosstex Holdings acquired a 100% interest in Crosstex Energy, Inc. (CEI), the general partner of the Predecessor, and a 100% limited partnership interest in the Predecessor. Also, effective May 5, 2000, the Predecessor was dissolved and Crosstex Holdings formed a new partnership, Crosstex Energy Services, Ltd., with the same management organization and purpose as the Predecessor. CEI was the managing and sole general partner and held a 1% interest in CES.

Crosstex Holdings is majority owned by Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. (collectively, Yorktown). Yorktown paid $21.9 million cash to capitalize Crosstex

Holdings in exchange for 100% of the common stock of Crosstex Holdings. Subsequently, Crosstex Holdings issued 722,771 shares of common stock to the management group of the Predecessor and CES in return for their 36.5% effective interest, resulting in CES management owning 25% of Crosstex Holdings and Yorktown owning the remaining 75%.

The accompanying consolidated financial statements include the results of operations of CES subsequent to the Yorktown transactions as of May 5, 2000.

Periods presented prior to May 5, 2000, relate to the Predecessor, and are not comparable in all respects to CES' financial statements due to a new basis of accounting established in connection with the Yorktown transaction.

The purchase price of $21.9 million was comprised of $13.9 million paid by Yorktown for an approximate 63.5% interest in the Predecessor and $800,000 cash and 722,711 shares of common stock of Crosstex Holdings valued at approximately $7.2 million issued to management in exchange for an approximate 36.5% economic interest held by management in the Predecessor. The purchase price of Crosstex Holdings which was pushed down to CES was allocated based on an estimated fair values as follows (in thousands):

Working capital	$	(9,604)
Property, plant, and equipment		11,804
Intangible assets		14,167
Goodwill		4,754
Investments		782
	$	21,903

Concurrent with the purchase of the Predecessor and the formation of CES, Crosstex Holdings contributed an additional $6.8 million as partner capital to CES for use as working capital and later during 2000 contributed another $10.0 million as partner capital.

(d) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities, and results of operations of the Predecessor prior to May 5, 2000 and the Partnership (or CES as its predecessor) and its wholly owned subsidiaries thereafter. The consolidated operations are hereafter referred to herein collectively as the "Partnership." All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for the prior year to conform to the current presentation.

(e) Unaudited Interim Information

The unaudited interim consolidated financial statements as of June 30, 2003 and for the six months ended June 30, 2003 and 2002, included herein, have been prepared pursuant to the rules and

regulations of the Securities and Exchange Commission (the "Commission"). Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete financial statements. In the opinion of management, the unaudited interim consolidated financial statements contain all adjustments (consisting of normal recurring adjustments) considered necessary for a fair presentation. The interim financial results are not necessarily indicative of operating results for an entire year.

(2) Significant Accounting Policies

(a) Management's Use of Estimates

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

(b) Cash and Cash Equivalents

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

(c) Property, Plant, and Equipment

Property, plant, and equipment consist of intrastate gas transmission systems, gas gathering systems, industrial supply pipelines, natural gas processing plants, and gas treating plants.

Other property and equipment is primarily comprised of furniture, fixtures, and office equipment. Such items are depreciated over their estimated useful life of five years. Property, plant, and equipment are recorded at cost, including capitalized interest. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest incurred during the construction period of new projects is capitalized and amortized over the life of the associated assets. Depreciation is provided using the straight-line method based on the estimated useful life of each asset, as follows:

	Useful Lives
Transmission assets	15 years
Gathering systems	7-15 years

Gas plants	10-15 years
Other property and equipment	5 years

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to

determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset. Impairments of approximately $2,873,000 and $4,175,000 associated with certain assets and the related intangible assets were recorded in the years ended December 31, 2001 and 2002, respectively. The impairments recorded in 2001 and 2002 relate primarily to customer relationships recorded as intangible assets as part of the Yorktown transaction. Due to changes impacting the expected future cash flows of the related assets, the Partnership determined the intangible assets were impaired under SFAS No. 121 or SFAS No. 144.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. 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. Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which would require us to record an impairment of an asset.

(d) Amortization of Intangibles

Until January 1, 2002, goodwill was amortized over the period of expected benefit. Goodwill related to the Yorktown transaction was being amortized on a straight-line basis over 15 years (see note 1). Such amortization was $296,000 for the year ended December 31, 2001. As discussed in note 2(n), the Partnership discontinued the amortization of goodwill effective January 1, 2002, with the adoption of SFAS No. 142.

Intangible assets are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which average 15 years. Such amortization was approximately $772,000 and $454,000 for the years ended December 31, 2001 and 2002, respectively. See impairment of intangibles discussed in note 2(c).

(e) Gas Imbalance Accounting

Quantities of natural gas over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted-average prices at the time the imbalance was created. These imbalances are typically settled with deliveries of natural gas. The Partnership had an imbalance payable of $422,000 and $149,000, and an imbalance receivable of $117,000 and $79,000 at December 31, 2001 and 2002, respectively. Imbalances are carried at the lower of cost or market value.

(f) Revenue Recognition

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

(g) Commodity Risk Management

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

Prior to January 1, 2001, these agreements were accounted for as hedges using the deferral method of accounting. Unrealized gains and losses were generally not recognized until the physical production required by the contracts was delivered. At the time of delivery, the resulting gains and losses were recognized as an adjustment to natural gas revenues. The cash flows related to any recognized gains or losses associated with these hedges were reported as cash flows from operations. If the hedge was terminated prior to maturity, gains or losses were deferred and included in income in the same period as the physical production required by the contracts was delivered.

Effective January 1, 2001, the Partnership adopted Statement of Financial Accounting Standards No. 133 (SFAS 133), *Accounting for Derivative Instruments and Hedging Activities*. This standard requires recognition of all derivative and hedging instruments in the statements of financial position as either assets or liabilities and measures them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying item being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. The impact of adopting SFAS No. 133 on January 1, 2001, was to record the fair value of derivatives as a liability in the amount of $1,006,000.

Currently, all derivative financial instruments that qualify for hedge accounting are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the gain or loss on these derivative instruments is recorded in other comprehensive income in partners' equity and reclassified into earnings in the same period in which the hedged transaction affects earnings. The asset or liability

related to the derivative instruments is recorded on the balance sheet in assets or liabilities from risk management activities. Any ineffective portion of the gain or loss is recognized in earnings immediately.

(h) Producer Services

The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that the Partnership does not own. The Partnership refers to these activities as part of Producer 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 Producer Services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance the Partnership's future commitments and significantly reduce its risk to the movement in natural gas prices. However, the Partnership is subject to counterparty risk for both the physical and financial contracts. Prior to October 26, 2002, the Partnership accounted for its Producer Services natural gas marketing activities as energy trading contracts in accordance with EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. EITF 98-10 required energy-trading contracts to be recorded at fair value with changes in fair value reported in earnings. In October 2002, the EITF reached a consensus to rescind EITF No. 98-10. Accordingly, energy trading contracts entered into subsequent to October 25, 2002, should be accounted for under accrual accounting rather than mark-to-market accounting unless the contracts meet the requirements of a derivative under SFAS No. 133. The Partnership's energy trading contracts qualify as derivatives, and accordingly, the Partnership continues to use mark-to-market accounting for both physical and financial contracts of its Producer Services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Partnership's Producer 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 contracts are reported as profit or loss on energy trading in the statements of operations.

Margins earned on settled contracts from its producer services activities included in (profit) loss on energy trading contracts in the consolidated statement of operations was ($638), ($1,206), ($1,946), and ($1,785) for the four months ended April 30, 2000, the eight months ended December 31, 2000 and the years ended December 31, 2001 and 2002, respectively.

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

	Four Months Ended April 30, 2000	Eight Months Ended December 31, 2000	Years Ended December 31, 2001	2002
Volumes purchased and sold	26,525,486	51,993,614	103,330,628	84,069,368

(i) Comprehensive Income (Loss)

During 1998, the Partnership adopted SFAS 130, *Reporting Comprehensive Income,* which establishes standards for reporting and display of comprehensive income and its components in a full set of general-purpose financial statements. Comprehensive income includes net income and other comprehensive income, which includes, but is not limited to, unrealized gains and losses on marketable securities, foreign currency translation adjustments, minimum pension liability adjustments, and effective January 1, 2001, unrealized gains and losses on derivative financial instruments. For the periods prior to January 1, 2001, comprehensive income and net income were equal and thus, SFAS No. 130 had no effect on the financial statements.

With the adoption of SFAS No. 133 on January 1, 2001, the Partnership began recording deferred hedge gains and losses on its derivative financial instruments that qualify as hedges as other comprehensive income.

(j) Income Taxes

No provision is made in the accounts of the Partnership for federal or state income taxes because such taxes are liabilities of the individual partners, and the amounts thereof depend upon their respective tax situations. The tax returns and amounts of allocable Partnership revenues and expenses are subject to examination by federal and state taxing authorities. If such examinations result in changes to allocable Partnership revenues and expenses, the tax liability of the Partners could be changed accordingly.

(k) Concentrations of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited, as the Partnership's customers represent a broad and diverse group of energy marketers and end users. In addition, the Partnership continually monitors and reviews credit exposure to its marketing counterparties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. As of December 31, 2001 and 2002, and June 30, 2003 the reserve for doubtful accounts was approximately $5.8 million, $0 million, and $0 million, respectively. See note 10 for further discussion.

During the four months ended April 30, 2000, the eight months ended December 31, 2000, and the years ended December 31, 2001 and 2002, the Partnership had 2, 3, 3, and 1 customers, respectively,

which individually accounted for more than 10% of consolidated revenues. The relevant percentages for these customers were: (i) for the four months ended April 30, 2000 - 50.4% and 21.1%; (ii) for the eight months ended December 31, 2000 - 28.8%, 20.7%, and 14.1%; (iii) for the year ended December 31, 2001 - 23.9%, 13.4%, and 11.5%; and (iv) for the year ended December 31, 2002 - 27.5%. While these customers represent a significant percentage of revenues, the loss of any of these would not have a material adverse impact on the Partnership's results of operations.

(l) Environmental Costs

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscontinued basis when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For the four months ended April 30, 2000, the eight months ended December 31, 2000 and the years ended December 31, 2001 and 2002, such expenditures were not significant.

(m) Crosstex Holdings' Option Plan

The Partnership applies the provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), and the related interpretations in accounting for the plan. In accordance with APB No. 25, compensation is recorded to the extent the fair value of the stock exceeds the exercise price of the option at the measurement date. Compensation expense of $0, $0 and $41,000 was recognized in 2000, 2001 and 2002, respectively.

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

	Eight Months Ended December 31, 2000	Year Ended December 31, 2001	Year Ended December 31, 2002	Six Months Ended June 30, 2002	Six Months Ended June 30, 2003
				(unaudited)	
Net income (loss), as reported	$ 1,623	$ (3,918)	$ 2,002	$ (28)	$ 5,807
Add: Stock-based employee compensation expense included in reported net income	—	—	41	—	3,072
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	103	226	328	153	3,289
Pro forma net income (loss)	$ 1,520	$ (4,144)	$ 1,715	$ (181)	$ 5,590

Actual and pro forma earnings per unit for the period December 17, 2002 through December 31, 2002 would have been $0.04 per unit. Actual and pro forma earnings per unit for the six months ended June 30, 2003 would have been $0.77 and $0.74 per unit. Per unit amounts are not presented for periods prior to our initial public offering.

The fair value of each option is estimated on the date of grant using the Black Scholes option-pricing model with the following weighted-average assumptions used for grants in 2000, 2001, 2002 and the six months ended June 30, 2003:

	Crosstex Energy Holdings Inc.			Crosstex Energy, L.P.	
					Six Months Ended June 30,
	2000	2001	2002	2002	2003
Dividend yield	0%	0%	0%	10%	10%
Expected volatility	0%	0%	0%	24%	24%
Risk free interest rate	6.9%	5.8%	4.1%	2.2%	2.88%
Expected life	3 years	3 years	3 years	3 years	5 years
Contractual life	4.6	3.6	3	10	10
Weighted average of fair value of options granted	$ —	$ —	$ —	$ 1.15	$ 2.76
Fair value of $10 options granted	2.04	3.27	3.17	—	—
Fair value of $12 options granted	—	1.52	1.40	—	—
Fair value of $14 options granted	—	—	0.91	—	—

Modification of Options

Crosstex Holdings modified certain outstanding options in the first quarter of 2003, which allows the option holders to elect to be paid in cash for the modified options based on the fair value of the options. The total number of Crosstex Holdings options, which have been modified is approximately 242,000. These modified options have been accounted for using variable accounting as of the option modification date. The Partnership will account for the modified options until the holders elect to cash out the options or the election to cash out the options lapses. Crosstex Holdings is responsible for paying the intrinsic value of the options for the holders who elect to cash out their options. Beginning in the first quarter of 2003, the Partnership will recognize stock compensation expense based on the estimated fair value at period end of the options modified. The Partnership recognized stock-based compensation expense of approximately $3.1 million for the six months ended June 30, 2003.

(n) New Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations,* requiring business combinations entered into after June 30, 2001, to be accounted for using the purchase method of accounting. Specifically identifiable intangible assets acquired, other than

goodwill, will be amortized over their estimated useful economic life. This pronouncement had no effect on the Partnership's financial position or results of operations.

In June 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets.* SFAS No. 142 requires, among other things, that companies no longer amortize goodwill, but instead test goodwill for impairment at least annually. In addition, SFAS No. 142 requires that the Partnership identify reporting units for purposes of assessing potential future impairments of goodwill, reassess the useful lives of other existing recognized intangible assets and cease amortization of intangible assets with an indefinite useful life. An intangible asset with an indefinite useful life should be tested for impairment in accordance with the guidance in SFAS No. 142. This statement is required to be applied in the fiscal years beginning after December 15, 2001 to all goodwill and other intangible assets recognized at that date, regardless of when those assets were initially recognized. SFAS No. 142 required the Partnership to complete a transitional goodwill impairment test within six months from the date of adoption and reassess the useful lives of other intangible assets within the first interim quarter after adoption. The Partnership had $4,873,000 recorded for goodwill, net of accumulated amortization at December 31, 2001 and recorded goodwill amortization expense of $296,000 for the year ended December 31, 2001.

The following table shows the Partnership's net earnings excluding goodwill amortization for the four months ended April 30, 2000, the eight months ended December 31, 2000, and the year ended December 31, 2001 and 2002 (in thousands).

	Four Months Ended April 30, 2000	Eight Months Ended December 31, 2000	Year Ended December 31, 2001	Year Ended December 31, 2002
Reported net income (loss)	$ (7,677)	$ 1,623	$ (3,918)	$ 2,002
Goodwill amortization	22	178	296	—
Adjusted net income (loss)	$ (7,655)	$ 1,801	$ (3,622)	$ 2,002

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement establishes standards for accounting for obligations associated with the retirement of tangible long-lived assets. This standard is required to be adopted by the Partnership beginning on January 1, 2003. The Partnership does not presently have any significant asset retirement obligations, and accordingly, the adoption of SFAS No. 143 is not expected to have a significant impact on our results of operations or financial condition.

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* SFAS No. 144 addresses financial accounting and reporting for impairment or disposal of long-lived assets. This statement supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets to Be Disposed Of,* and the accounting and reporting provisions of APB Opinion No. 30, *Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business,*

and Extraordinary, Unusual and Infrequently Occurring Events and Transactions, for the disposal of a segment of a business. This statement also amends APB No. 51, *Consolidated Financial Statements,* to eliminate the exception to consolidation for a subsidiary for which control is likely to be temporary. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001. See the impact of the adoption of SFAS No. 144 at note 2(c).

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* SFAS 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred rather than when the entity commits to an exit plan. This standard is effective for all exit or disposal activities which are initiated after December 31, 2002. The Partnership does not anticipate the adoption of SFAS 146 will have any impact on its financial position or results of operations.

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

In June 2002, the Emerging Issues Task Force (EITF) reached consensus on certain issues in EITF Issue No. 02-03, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts.* Consensus was reached on two issues: 1) that gains and losses on energy trading contracts (whether realized or unrealized) should be shown net in the statement of operations, and 2) that entities should disclose the types of contracts that are accounted for as energy trading contracts along with a variety of other data regarding values, sensitivity to changes in estimates, maturity dates, and other factors. The Partnership early adopted this consensus in the second quarter of 2002 and all comparative financial statements were reclassified to report gains or losses on energy trading contracts net in the statements of operations. In October 2002, the EITF reached a consensus to rescind EITF 98-10. Accordingly, energy related contracts that are not accounted for pursuant to SFAS No. 133 should be accounted for as executory contracts and carried on an accrual basis, not fair value. The consensus should be applied prospectively to all new energy trading contracts entered into after October 25, 2002 and to all contracts that existed on October 25, 2002, in periods beginning after December 15, 2002. Changes to the accounting for existing contracts as a result of the rescission of EITF 98-10 will be reported as a cumulative effect of a change in accounting principles. The rescission of EITF 98-10 did not have any significant effect on the Partnership's financial position or results of operations.

In January 2003, the FASB issued FASB Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. FIN

No. 45 requires an entity to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. Certain guarantees are excluded from the measurement provisions of the Interpretation. The measurement provisions of this statement apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure provisions of the statement apply to financial statements for periods ending after December 15, 2002. The adoption of the statement is not expected to have a material effect on the Partnership's financial statements when adopted.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51.* FIN No. 46 requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception for any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this Interpretation must be applied at the beginning of the first interim or annual period beginning after June 15, 2003. The Partnership is not the primary beneficiary of any significant variable interest entities.

(3) Significant Asset Purchases and Acquisitions

On August 16, 2000, CES entered into a purchase and sale agreement with Western Gas Resources, Inc. to acquire certain natural gas gathering and related facilities known as the Arkoma System for a total purchase price of $10,500,000, which was allocated entirely to transmission assets. CES recorded the net assets acquired based on relative fair values, and CES' results of operations include the results of the Arkoma System as of September 1, 2000.

On September 14, 2000, CES entered into a purchase and sale agreement with Tejas Hydrocarbons LLC to acquire all of the assets of GC Marketing Company (a Texas general partnership), for a total purchase price of $10,632,209, after closing adjustments. CES recorded the net assets acquired based on relative fair values and the CES' results of operations include the results of GC Marketing Company as of October 1, 2000.

The purchase price consisted of the following (in thousands):

Transmission assets	$	10,716
Other property, plant, and equipment		131
Miscellaneous liabilities		(215)
	$	10,632

On April 3, 2001, CES entered into a purchase and sale agreement with Tejas Energy NS, LLC to acquire all of the assets of Tejas Texas Pipeline GP, LLC, a Delaware limited liability company, and Tejas C Pipeline LP, LLC, a Delaware limited liability company, for a total purchase price of

$30,003,120, after closing adjustments. CES recorded the net assets acquired based on relative fair values, and CES' results of operations include the results of operations of the acquired assets as of May 1, 2001.

The purchase price consisted of the following (in thousands):

Gas plant	$	11,837
Gathering systems		10,192
Transmission assets		7,158
Other property, plant, and equipment		816
	$	30,003

On October 11, 2001, CES entered into a purchase and sale agreement with various individuals to acquire the common stock of Millennium Gas Services, Inc. (Millennium) for a total of $2,124,000 after closing adjustments, which was allocated entirely to treating plants. CES' results of operations include the results of Millennium as of October 1, 2001.

On June 6, 2002, CES acquired 70 miles of then-inactive pipeline from Florida Gas Transmission Company for $1,500,000 in cash and a $800,000 note payable. On June 7, 2002, CES acquired the Pandale gathering system which is connected to two treating plants, one of which (the Will-O-Mills Plant) was half-owned by the Partnership, from Star Field Services for $2,156,000 in cash. The Partnership purchased the other one-half interest in the Will-O-Mills Plant on December 30, 2002 for $2,200,000 in cash.

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

On June 30, 2003, we completed the acquisition of certain assets from Duke Energy Field Services, L.P. for $67.3 million, including the effect of certain purchase price adjustments. The assets acquired included: the AIM pipeline system, a 12.4% interest in the Seminole gas processing plant, the Conroe gas plant and gathering system, the Black Warrior pipeline system and two small gathering systems in Louisiana. We have accounted for this acquisition as a business combination in accordance with SFAS No. 141, Business Combinations. We have utilized the purchase method of accounting for this

acquisition with an acquisition date of June 30, 2003. The purchase price and allocation thereof is as follows:

Purchase price to DEFS	$	66.4	million
Direct acquisition costs		0.9	million
Total Purchase Price	$	67.3	million
Current assets acquired	$	0.4	million
Liabilities assumed		(0.8)	million
Property plant and equipment		66.8	million
Intangible assets		0.9	million
Total Purchase Price	$	67.3	million

Intangible assets relate to customer relationships and will be amortized over seven years. The purchase price allocation is preliminary and may be adjusted for post-closing adjustments. Pro forma results of operations as if the acquisition from DEFS had been acquired on January 1, 2002 are as follows:

	Six Months Ended June 30,	
	2003	**2002**
	(in thousands except per share amounts)	
Revenue	$ 586,144	$ 268,104

Net income		6,797	65
Net income per Limited partner unit	$	0.91	N/A

(4) Investment in Limited Partnerships

The Partnership owns a 7.86% weighted-average interest as the general partner in the five gathering systems of Crosstex Pipeline Company (CPC), a 20.31% interest as a limited partner in CPC, a 50% interest in J.O.B. J.V. and a 50% interest in Crosstex Denton County Gathering, J.V. The Partnership accounts for its investments under the equity method, as it exercises significant influence in operating decisions as a general partner. Under this method, the Partnership records its equity in net earnings of the affiliated partnerships as income in other income (expense) in the consolidated statement of operations, and distributions received from them are recorded as a reduction in the Partnership's investment in the affiliated partnership.

(5) Long-Term Debt

In February 2000, the Predecessor and Union Bank of California, N.A. (UBOC) entered into a $22 million secured credit facility, which was amended in May 2000 for the creation of CES. In

August 2000, the Partnership and UBOC amended the credit facilities to create a Revolver A of $22 million and a Revolver B of $12 million. Revolver A was available for general corporate purposes, including the acquisition and installation of property and equipment. Revolver B was available to finance letters of credit and certain working capital requirements. In December 2001, the credit facilities were amended to increase the availability under Revolver A to $60 million and Revolver B to $15 million, thereby increasing the credit facilities to $75 million.

In connection with the Partnership's initial public offering, the Partnership amended the secured credit facility to provide a $67.5 million credit facility consisting of:

- a senior secured revolving acquisition facility in the aggregate principal amount of $47.5 million; and
- a senior secured revolving working capital and letter of credit facility in the aggregate principal amount of $20.0 million.

In June 2003, CES, L.P. entered into a $100 million senior secured credit facility with Union Bank of California, N.A. (as a lender and as administrative agent) and other lenders, consisting of the following two facilities:

- a $70.0 million senior revolving acquisition facility; and
- a $30.0 million senior secured revolving working capital and letter of credit facility.

The acquisition facility 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, 2002, $21.8 million was outstanding under the acquisition facility, leaving approximately $25.7 available for future borrowings. The acquisition facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the acquisition credit facility may be reborrowed.

The working capital and letter of credit facility will be used for ongoing working capital needs, letters of credit, distributions and general partnership purposes, including future acquisitions and expansions. At December 31, 2002, $13.1 million of letters of credit were issued under the working capital and letter of credit facility, leaving approximately $6.9 million available for future issuances of letters of credit, or up to $5.0 million of cash borrowings. The aggregate amount of borrowings under the working capital and letter of credit facility is subject to a borrowing base requirement relating to the amount of our cash and eligible receivables (as defined in the credit agreement), and there is a $10.0 million sublimit for cash borrowings. This facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the working capital and letter of credit facility may be reborrowed. The Partnership will be required to reduce all working capital borrowings to zero for a period of at least 15 consecutive days once a year.

The obligations under the credit facility are secured by first priority liens on all of the Partnership's material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of the Partnership's equity interests in certain of the Partnership's subsidiaries, and

ranks *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by certain of the Partnership's subsidiaries and the Partnership. The Partnership may prepay all loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

Indebtedness under the acquisition facility and the working capital and letter of credit facility bear interest at our option at the administrative agent's reference rate plus 0.25% to 1.5% or LIBOR plus 1.75% to 3.00%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.50% 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, limit the Partnership's ability to:

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

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

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

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

- a minimum tangible net worth (as defined in the credit agreement) of $60.0 million, plus one-half of certain equity contribution.

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

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

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

Senior Secured Notes. In June 2003, CES, L.P. 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, CES, L.P. 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.

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

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

The senior secured notes are redeemable, at CES, L.P.'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 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.

As of June 30, 2003, due to the timing of the financing associated with the acquisition of assets from DEFS, the Partnership was not in compliance with the current ratio restrictions under the bank credit facility and the master shelf agreement governing the senior secured notes. In August 2003, the Partnership obtained waivers of this restriction from the bank credit facility and the senior secured note participants. The Partnership was in compliance with all debt covenants at December 31, 2002, and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement in June 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. This agreement appointed Union Bank of California, N.A. to act as collateral agent and authorized Union Bank to execute various security documents on behalf of the lenders under the bank credit facility and the initial purchases of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing Crosstex Energy Services, L.P.'s obligations under the bank credit facility and the master shelf agreement.

In June 2002, as part of the purchase price of Florida Gas Transmission Company (FGTC), the Partnership issued a note payable for $800,000 to FGTC that is payable in $50,000 annual increments starting June 2003 through June 2006 with a final payment of $600,000 due in June 2007. The note bears interest payable annually at LIBOR plus 1%.

As of December 31, 2001 and 2002 and June 30, 2003, long-term debt consisted of the following (in thousands):

	December 31,		June 30,
	2001	2002	2003
Revolver A Facility, interest based on prime, interest rate at December 31, 2001 was 5.75%	$ 17,500	$ —	$ —
Revolver A Facility, based on LIBOR, interest rate at December 31, 2001 was 4.67%	10,500	—	—
Revolver A Facility, based on LIBOR, interest rate at December 31, 2001 was 4.40%	32,000	—	—
Acquisition credit facility, interest based at prime plus an applicable margin, interest rate at December 31, 2002 was 4.88%	—	1,750	68,000
Acquisition credit facility, interest based on LIBOR plus an applicable margin, interest rate at December 31, 2002 was 3.95%	—	20,000	—
Senior secured notes, interest rate at June 30, 2003 was 6.95%	—	—	30,000
Note payable to Florida Gas Transmission Company	—	800	750
	60,000	22,550	98,750
Less current portion	—	50	50
Debt classified as long-term	$ 60,000	$ 22,500	$ 98,700

Maturities for the long-term debt as of December 31, 2002 are as follows (in thousands):

2003	$ 50
2004	2,225
2005	4,400
2006	4,400
2007	11,475
Thereafter	—

In October 2002, the Partnership entered into an interest rate swap covering a principal amount of $20 million for a period of two years. The Partnership is subject to interest rate risk on its acquisition credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 2.29%, on $20 million of related debt outstanding over the term of the swap agreement. The Partnership has accounted for this swap as a cash flow hedge of the variable interest payments related to the $20 million of the acquisition credit facility outstanding. Accordingly, unrealized gains or losses relating to the swap which are recorded in other comprehensive income will be reclassified from other comprehensive income to interest expense over the period hedged.

(6) Partners' Capital

(a) Initial Public Offering

On December 17, 2002, the Partnership completed its initial public offering of 2,300,000 common units representing limited partner interests at a price of $20.00 per common unit. Total proceeds from the sale of the 2,300,000 units were $46.0 million, before offering costs and underwriting commissions. Concurrent with the closing of the initial public offering, the Partnership entered into a $67.5 million credit facility with a syndicate of banks led by UBOC, that provides for a $47.5 million acquisition credit facility and a $20 million working capital facility (see note 5). On December 17, 2002, the Partnership had borrowings of $20 million under the acquisition credit facility.

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

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

Total use of proceeds	$	46,000

The Crosstex Energy, L.P. partnership agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts.

(b) Limitation of Issuance of Additional Common Units

During the subordination period, the Partnership may issue up to 1,316,500 additional common units or an equivalent number of securities ranking on a parity with the common units without obtaining unitholder approval. The Partnership may also issue an unlimited number of common units during the subordination period for acquisitions, capital improvements or debt repayments that increase cash flow from operations per unit on a pro forma basis.

(c) Subordination Period

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

(d) Early Conversion of Subordinated Units

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

(e) Cash Distributions

In accordance with the partnership agreement, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter commencing with the quarter ending on March 31, 2003. Distributions will generally be made 98% to the common and subordinated unitholders and 2% to the general partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. If cash distributions exceed $0.50 per unit in a quarter, the general partner will receive incentive distributions up to 50% of the cash distributed in excess of $0.50 per unit. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.50 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The Partnership paid its initial distribution on its common and subordinated units of $0.576 on May 15, 2003. The distribution consisted of $0.076 covering the period from the closing of the Partnership's IPO through December 31, 2002, and $0.50 covering the first quarter of 2003. The second quarter distribution of $0.55 per unit was paid on August 15, 2003 to holders of record on July 31, 2003.

(7) Retirement Plans

The Partnership sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The Partnership, as stated within the plan document, will make discretionary contributions at the end of the year. There were no contributions during the four months ended April 30, 2000 and the eight months ended December 31, 2000. Contributions for the years ended December 31, 2001 and 2002 totaled $116,000 and $198,000, respectively.

(8) Employee Incentive Plans

(a) Long-Term Incentive Plan

In December 2002, the Partnership's managing general partner adopted a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently

permits the grant of awards covering an aggregate of 700,000 common units, 233,000 of which may be awarded in the form of restricted units and 467,000 of which may be awarded in the form of unit options. The plan is administered by the compensation committee of the managing general partner's board of directors.

(b) Restricted Units

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

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units.

As of December 31, 2002, there were no restricted units issued under the long-term incentive plan. During May 2003, the Partnership approved the issuance of 48,000 restricted unit grants. Compensation expense is recognized over the five year vesting period of these restricted units.

(c) Unit Options

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

A summary of the unit option activity for the period December 17, 2002 through December 31, 2002 is provided below:

	December 31, 2002		
	Number of Units		Weighted-Average Exercise Price
Outstanding, beginning of period	—		—
Granted	175,000	$	20.00
Exercised	—		—
Forfeited	—		—
Outstanding, end of period	175,000	$	20.00
Options, exercisable at end of period	—		—
Weighted average fair value of options granted		$	1.15

All options outstanding have a remaining contractual life of 10 years at December 31, 2002.

The Partnership accounts for option grants in accordance with APB No. 25, *Accounting for Stock Issued to Employees* and follows the disclosure only provision of SFAS No. 123, *Accounting for Stock-based Compensation*.

During the period ended June 30, 2003, the Partnership granted an additional 91,910 unit options with an exercise price of $20.

(d) Crosstex Holdings' Option Plan

Crosstex Holdings has one stock-based compensation plan, the 2000 Stock Option Plan. Crosstex Holdings applies the provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), and the related interpretations in accounting for the plan. In accordance with APB No. 25, compensation is recorded to the extent the fair value of the stock exceeds the exercise price of the option at the measurement date. Compensation expense of $0, $0, and $41,000 was recognized in 2000, 2001, and 2002, respectively.

A summary of the status of the 2000 Stock Option Plan as of December 31, 2001 and 2002, is presented in the table below:

	December 31, 2001			December 31, 2002		
	Shares		Weighted-Average Exercise Price	Shares		Weighted-Average Exercise Price
Outstanding, beginning of period	228,000	$	10.00	340,500	$	10.32
Granted	130,500		10.93	166,250		11.89
Exercised	—		—	—		—
Forfeited	18,000		12.00	6,500		12.00
Outstanding, end of period	340,500		10.32	500,250		10.77
Options, exercisable at period end	76,000		10.00	288,503		10.38
Weighted-average fair value of options granted			2.85			N/A
Fair value of $10 options granted			N/A			3.17
Fair value of $12 options granted			N/A			1.40
Fair value of $14 options granted			N/A			0.91

All options outstanding have an exercise price ranging from $10 to $14 at December 31, 2002.

Crosstex Holdings modified certain terms of certain outstanding options in the first quarter of 2003. These modifications resulted in variable award accounting for the modified options. Total compensation expense was approximately $3.1 million which was recorded by the Partnership as non-cash stock based compensation expense during the six months ended June 30, 2003. Compensation expense in future periods will be adjusted for changes in the unit market price and the remaining unvested portion.

(e) Earnings per unit and anti-dilutive computations

Basic earnings per unit was computed by dividing net income, by the weighted-average number of limited partner units outstanding for the periods December 17, 2002 through December 31, 2002 and January 1, 2003 through June 30, 2003. The computation of diluted earnings per unit further assumes the dilutive effect of unit options.

The following are the share amounts used to compute the basic and diluted earnings per limited partner unit for the periods December 17, 2002 through December 31, 2002 and the six months ended June 30, 2003 (in thousands, except per-unit amounts):

	December 17, 2002 Through December 31, 2002	Six Months Ended June 30, 2003
Basic earnings per unit:		
Weighted-average limited partner units outstanding	7,300	7,300
Dilutive earnings per unit:		
Weighted-average limited partner units outstanding	7,300	7,300
Dilutive effect of exercise of options outstanding	10	66
Dilutive units	7,310	7,366

All outstanding units were included in the computation of diluted earnings per unit.

(9) Fair Value of Financial Instruments

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

	2001		2002	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 352	$ 352	$ 1,308	$ 1,308
Trade accounts receivable	58,222	58,222	104,802	104,802
Assets from energy risk management	3,478	3,478	3,102	3,102
Account receivable from Enron	2,467	2,467	—	—
Accounts payable and accrued gas purchases	56,092	56,092	110,793	110,793
Long-term debt	60,000	60,000	22,550	22,550
Liabilities from energy risk management	8,005	8,005	4,277	4,277

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility, which accrues interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value for the amounts outstanding under the credit facility.

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

(10) Risk Management and Financial Instruments

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge prices and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2001 and 2002 and June 30, 2003 (all quantities are expressed in MMBtus, and all prices are expressed in the Houston Ship Channel Inside FERC (HSC IF), Natural Gas Pipeline Inside FERC (NGPL IF), Texas Eastern South Texas Inside FERC (TET STx IF), Reliant East Inside FERC (Reliant E IF) or Texas Eastern East Texas Inside FERC (TET Etx IF) for natural gas). The remaining term of the contracts extend no later than December 2004, with no single contract longer than 16 months. The Partnership's counterparties to hedging contracts include Morgan Stanley, Tractebel, Williams, Duke and Sempra. As discussed in note 2, changes in the fair value of the Partnership's derivatives related to Producer Services gas marketing activities are recorded in earnings.

The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings.

December 31, 2001

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
Cash flow hedge swaps	(360,000)	$2.905 vs. Reliant E IF to $3.1525 vs. Reliant E IF	January - December 2002	$ 122,880

Cash flow hedge swaps	720,000	$2.60 vs. HSC IF to $5.96 vs. HSC IF	January 2002	19,200
Marketing trading transaction swaps	(43,383)	$2.625 vs. HSC IF to $5.715 vs. HSC IF	January - December 2002	(1,649,247)
Marketing trading transaction swaps	(1,147,500)	$3.10 vs. TET Etx IF to $3.14 TET Etx IF	January 2003 - April 2004	(113,607)

December 31, 2002

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
Cash flow hedge swaps	(500,000)	$3.285 vs. Reliant E IF to $4.01 vs. Reliant E IF	January 2003 - April 2004	$ (421,800)
Cash flow hedge swaps	(440,000)	$3.415 vs. HSC IF to $4.99 vs. HSC IF	January - September 2003	(573,320)
Marketing trading transaction swaps	(1,149,000)	$3.10 vs. TET Etx IF to $3.14 vs. TET Etx IF	January 2003 - April 2004	(1,593,421)
Marketing trading transaction swaps	(1,096,000)	$3.21 vs. HSC IF to $5.16 vs. HSC IF	January - October 2003	(441,277)
Marketing trading transaction swaps	(180,000)	$3.185 vs. Reliant E IF to $3.635 vs. Reliant E IF	January - May 2003	(219,330)

June 30, 2003

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
Cash flow hedge swaps	(820,000)	$3.285 vs. Reliant E IF to $6.06 vs. Reliant E IF	July 2003 - June 2004	$ (384,400)
Cash flow hedge swaps	2,887,000	$4.15 vs. HSC IF to $6.545 vs. HSC IF	July 2003 - December 2004	(1,588,011)
Cash flow hedge swaps	(120,000)	$5.48 vs. NGPL IF to $5.51 vs. NGPL IF	July - August 2003	28,290
Cash flow hedge swaps	(226,000)	$5.36 vs. TET STx IF to $5.92 vs. TET STx IF	July 2003 - March 2004	89,616
Marketing trading transaction swaps	(456,000)	$3.14 vs. TET Etx IF	July 2003 - April 2004	(1,049,802)
Marketing trading transaction swaps	244,000	$3.935 vs. HSC IF to $6.145 vs. HSC IF	July 2003 - May 2004	(833,593)

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits, and monitors the appropriateness of these limits on an ongoing basis.

Assets and liabilities related to Producer Services that are accounted for as energy trading contracts are included in assets and liabilities from risk management activities. Assets and liabilities related to Producer Services were as follows:

	December 31, 2001	December 31, 2002	June 30, 2003
	(In thousands)		
Assets from risk management activities:			
Current	$ 3,196	$ 2,947	$ 819
Long-term	117	155	1
Liabilities from risk management activities:			
Current	$ 7,541	$ 3,046	$ 2,654
Long-term	440	236	20

The Partnership estimates the fair value of all of its energy trading contracts using prices actively quoted. The estimated fair value of energy trading contracts by maturity date was as follows (in thousands):

	Maturity Periods			
	Less Than One Year	One to Two Years	Two to Three Years	Total Fair Value
December 31, 2001	$ (4,345)	$ (242)	$ (81)	$ (4,668)
December 31, 2002	(99)	(81)	—	$ (180)
June 30, 2003	(1,835)	(19)	—	$ (1,854)

The following reconciles the changes in fair value of energy trading contracts related to producer services activities from the beginning of each period to the end of the period.

	December 31,		
	2000	2001	2002
	(In thousands)		
Fair value of contracts at beginning of period	$ —	$ 47	$ (4,668)
Unrealized gains (losses)	47	(5,660)	4,488
Unrealized gains (losses) attributable to changes in valuation techniques and assumptions	—	—	—
Realized gains (losses) related to offsetting Enron contracts		—	(3,541)
Realized gains on settled contracts	1,206	1,946	1,756
Profit (loss) on energy trading contracts	1,253	(3,667)	(1,965)
Cash (received) paid on settled contracts	(1,206)	(1,946)	1,785
Purchase of financial contracts	—	945	—
Fair value of contracts at end of period	$ 47	$ (4,668)	$ (180)

Termination of Enron Positions

On December 2, 2001, Enron Corp. and certain subsidiaries, including Enron North America Corp. (Enron), each filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code. Enron failed to make timely payment of approximately $3.9 million for physical deliveries of gas in 2001. This amount remained outstanding as of December 31, 2002. Additionally, the Partnership had entered into natural gas hedging and physical delivery contracts with Enron. According to the terms of the contracts, Enron is liable to the Partnership for the mark-to-market value of all contracts outstanding on the date the Partnership exercised its termination right under the contracts, which totaled approximately $4.6 million and which was recorded as a receivable from Enron. The Partnership has accounted for these contracts as energy trading contracts whereby changes in fair value of the fixed price purchase and sales commitments are recognized in earnings.

The Partnership had offsets to the above amounts totaling approximately $0.3 million, resulting in a net amount of $8.2 million receivable from Enron at December 31, 2001. Due to the uncertainty of future collections, a charge and related allowance for 70% of the net receivable, or $5.7 million, was recorded at December 31, 2001. The 30% recovery rate was management's best estimate based on current market transactions. Due to the uncertainty of the timing of recovery of this receivable due to Enron's bankruptcy, the Partnership classified this receivable as long-term at December 31, 2001. No

balance is reflected at December 31, 2002 as the receivable was transferred to Crosstex Holdings in conjunction with the initial public offering of the Partnership.

For the year ended December 31, 2001, the Partnership recorded a loss on energy trading contracts related to natural gas marketing of $5.7 million, substantially all of which related to estimated losses on claims from Enron. This loss was partially offset by gains of $1.9 million on energy trading contracts which physically settled during 2001.

The Partnership had fixed price sales commitments to Enron which offset fixed price purchase commitments from producers. Due to Enron's bankruptcy, the Partnership was exposed to future natural gas price movements related to the fixed price purchase commitments. The Partnership entered into new fixed price sales commitments with a new counterparty for a portion of the volume, and purchased or sold exchange-traded natural gas option contracts to mitigate the effects of future price declines. The change in fair value of these sales contracts and options is recorded in earnings as profit or loss on energy trading contracts.

Option contracts outstanding related to the fixed price purchase commitments at December 31, 2001 were as follows:

December 31, 2001				
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
Purchased puts	3,840,000	$2.50 vs. NYMEX Natural Gas to $2.70 vs. NYMEX Natural Gas	February - October 2002	$ 1,184,600

The Enron receivable was distributed to Crosstex Holdings prior to the initial public offering of Crosstex Energy, L.P.

(11) Transactions with Related Parties

General and Administrative Expense Cap

The Partnership has a $6.0 million annual ($1.5 million quarterly) general and administrative cap for the twelve month period ending in December 2003, per the partnership agreement. Crosstex Energy Holdings Inc. bears the cost of any excess general and administrative expenses. During the six months ended June 30, 2003, the Partnership had excess expenses of approximately $1.2 million. The general partner is also reimbursed for direct charges it incurs on behalf of partnership business development activities. Such charges totaled $0.4 million for the six months ended June 30, 2003 and are included in general and administrative expenses.

Camden Resources, Inc.

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden). Camden is an affiliate of the Partnership by way of equity investments made by Yorktown in Camden. During the eight months ended December 31, 2000 and the years ended December 31, 2001 and 2002, the Partnership purchased natural gas from Camden in the amount of approximately $2,645,000, $17,300,000, and $10,076,000, respectively, and received approximately $53,000, $737,000, and $399,000 in treating fees from Camden. During the six months ended June 30, 2002 and 2003, the Partnership purchased natural gas from Camden in the amount of approximately $3.6 million and $5.5 million, respectively, and received approximately $182,408 and $214,109 in treating fees from Camden.

Subsequent to April 30, 2000, the Partnership had related-party transactions with Crosstex Pipeline Company (CPC), and prior to that date, the Partnership had related-party transactions with Crosstex Energy, Inc. (CEI), CPC, Vantex Energy Services (VES), Texas Energy Transfer Company (TETC), and Energy Transfer Company (ETC), all of which are summarized below:

- During the four months ended April 30, 2000 the Partnership paid management fees of $13,000, to CEI for their services in managing and supervising the operation of the Partnership.
- During the four months ended April 30, 2000, the Partnership bought natural gas from CPC in the amount of $1,426,000, and paid for transportation of $7,000 to CPC.
- The Partnership also reimbursed ETC for costs incurred on behalf of the Partnership of $13,000 in the four months ended April 30, 2000.
- The Partnership sold natural gas to TETC during the four months ended April 30, 2000, in the amount of $234,000, and bought natural gas from TETC in the amount of $54,000.
- During the eight months ended December 31, 2000, the Partnership received a management fee from CPC in the amount of approximately $81,000.
- During the eight months ended December 31, 2000, the Partnership bought natural gas from CPC in the amount of approximately $4.6 million and paid for transportation of approximately $22,000 to CPC.
- During the eight months ended December 31, 2000, the Partnership received distributions from CPC in the amount of approximately $232,000.
- During the years ended December 31, 2001 and 2002, the Partnership bought natural gas from CPC in the amount of approximately $6,500,000 and $3,400,000 and paid for transportation of approximately $31,000 and $27,500, respectively, to CPC.
- During the years ended December 31, 2001 and 2002, the Partnership received a management fee from CPC in the amount of approximately $125,000 and $125,000, respectively.
- During the years ended December 31, 2001 and 2002, the Partnership received distributions from CPC in the amount of approximately $152,000 and $89,982, respectively.

- During the six months ended June 30, 2002 and 2003, the Partnership bought natural gas from CPC in the amount of approximately $1.6 million and $3.8 million and paid for transportation of approximately $11,734 and $23,495, respectively, to CPC.
- During the six months ended June 30, 2002 and 2003, the Partnership received a management fee from CPC in the amount of approximately $62,723 for each period.
- During the six months ended June 30, 2002 and 2003, the Partnership received distributions from CPC in the amount of approximately $50,475 and $58,270, respectively.

(12) Commitments and Contingencies

(a) Leases

Leased office space and equipment have remaining noncancelable lease terms in excess of one year. The following table summarizes our remaining noncancelable future payments under operating leases as of December 31, 2002:

2003	$	841,942
2004		751,288
2005		567,558
2006		71,971
2007		—
Thereafter		—

Operating lease rental expense in the four months ended April 30, 2000, the eight months ended December 31, 2000 and the years ended December 31, 2001 and 2002, was approximately $200,000, $608,000, $1,200,000 and $951,000, respectively.

Each member of senior management of the Partnership is a party to an employment contact with the general partner. The employment agreements provide each member of senior management with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

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

The Partnership has an agreement with a consulting firm which helped facilitate certain acquisitions for the Partnership. In addition to the regular fee received for their services, the consulting firm also entered into an agreement with the Partnership by which they would receive a 10% net profit interest from the acquired assets after the acquisitions have reached payout, which includes a 10% rate of return. The assets subject to the net profits interest generated approximately $3,224,000 in cash flow

during 2001. In December 2002, the Partnership acquired the interest for $684,000. The acquisition of the net profits interest has been accounted for as a cost of the related acquired assets.

(13) Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the Gulf Coast System, the Corpus Christi System, the Gregory gathering system located around the Corpus Christi area, the Arkoma system in Oklahoma and various other small systems. Also included in the Midstream division are the Partnership's Producer Services operations (note 2(h)). The Treating division generates fees from its plants either through volume-based treating contracts or though fixed monthly payments. Included in the Treating division are four gathering systems that are connected to the treating plants.

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

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

	Midstream	Treating	Totals
		(In thousands)	
Four months ended April 30, 2000:			
Sales to external customers	$ 3,591	$ 5,947	$ 9,538
Intersegment sales	4,883	(4,883)	—
Interest expense	57	22	79
Depreciation and amortization	243	279	522
Segment profit (loss)	(8,132)	455	(7,677)
Segment assets	34,947	10,104	45,051
Capital expenditures	—	3,026	3,026
Eight months ended December 31, 2000:			
Sales to external customers	$ 88,008	$ 17,392	$ 105,400
Intersegment sales	13,127	(13,127)	—
Interest expense	477	53	530
Depreciation and amortization	1,433	828	2,261
Segment profit	1,302	321	1,623
Segment assets	181,297	19,971	201,268
Capital expenditures	2,519	2,148	4,667
Year ended December 31, 2001:			
Sales to external customers	$ 362,673	$ 24,353	$ 387,026
Intersegment sales	10,633	(10,633)	—
Interest expense	1,840	413	2,253
Depreciation and amortization	4,534	1,567	6,101
Segment profit (loss)	(4,607)	689	(3,918)
Segment assets	137,303	31,073	168,376
Capital expenditures	6,484	16,201	22,685
Year ended December 31, 2002:			
Sales to external customers	$ 437,676	$ 14,817	$ 452,493
Intersegment sales	4,073	(4,073)	—
Interest expense	2,327	390	2,717
Depreciation and amortization	5,738	2,007	7,745
Segment profit (loss)	3,271	(1,269)	2,002
Segment assets	199,056	33,382	232,438
Capital expenditures	11,154	3,391	14,545

Six months ended June 30, 2002:						
Sales to external customers	$	200,595	$	6,878	$	207,473
Intersegment sales		9,322		(9,322)		—
Interest expense		1,456		240		1,696
Depreciation and amortization		2,550		1,334		3,884
Segment profit (loss)		(935)		907		(28)
Segment assets		181,102		29,709		210,811
Capital expenditures		5,316		659		5,975
Six months ended June 30, 2003:						
Sales to external customers	$	469,345	$	10,477	$	479,822
Intersegment sales		3,909		(3,909)		—
Interest expense		856		19		875
Depreciation and amortization		3,715		1,331		5,046
Segment profit		4,430		1,377		5,807
Segment assets		340,814		11,751		352,565
Capital expenditures		12,903		4,364		17,267

(14) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

		First		Second		Third		Fourth		Total
						(In thousands)				
2001:(1)										
Revenues	$	81,725	$	123,942	$	83,913	$	97,446	$	387,026
Operating income(2)		2,901		3,254		4,906		5,702		16,763
Net income (loss)		1,719		144		784		(6,565)(3)		(3,918)
2002:(1)										
Revenues	$	80,993	$	126,480	$	114,611	$	130,409	$	452,493
Operating income(2)		4,681		5,468		6,182		5,945		22,276
Net income (loss)		(252)(4)		224		1,485		545(4)		2,002

(1) The Partnership stopped amortizing goodwill effective January 1, 2002 with the adoption of SFAS No. 142. See Note 2(n).

(2) Operating income is defined as revenues less purchased gas less operating expenses.

(3) Included in the 2001 fourth quarter results is a charge of $5.8 million related to Enron write-offs as discussed in footnote (10), and an impairment of $2.9 million related to the impairment of certain intangible assets associated with an asset no longer owned by the Partnership.

(4) Included in the 2002 first and fourth quarter results are impairment charges of $3.2 million and $1.0 million, respectively, related to the impairment of certain intangibles related to gas plants.

Independent Auditors' Report

To the Partners of
Crosstex Energy GP, L.P.:

We have audited the accompanying balance sheet of Crosstex Energy GP, L.P. (a Texas limited partnership, the General Partner) as of December 31, 2002. This financial statement is the responsibility of the General Partner's management. Our responsibility is to express an opinion on this financial statement based on our audit.

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

In our opinion, the financial statement referred to above presents fairly, in all material respects, the financial position of Crosstex Energy GP, L.P. as of December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

KPMG LLP

Dallas, Texas,
June 28, 2003

CROSSTEX ENERGY GP, L.P.

Balance Sheets

December 31, 2002 and June 30, 2003 (unaudited)

(in thousands)

	December 31, 2002	June 30, 2003
		Unaudited
Assets		
Cash	$ 1	$ 1
Total current assets	1	1
Investment in Crosstex Energy, L.P.	1,016	1,163
Total assets	$ 1,017	$ 1,164
Partners' Equity		
Partners' equity	$ 1,017	$ 1,164
Total partners' equity	$ 1,017	$ 1,164

See accompanying notes to balance sheet.

CROSSTEX ENERGY GP, L.P.

Notes to Balance Sheets

December 31, 2002 and June 30, 2003 (unaudited)

(1) Organization

(a) Organization

Crosstex Energy GP, L.P. (the "General Partner") is a Delaware limited partnership formed on July 12, 2002, to become the General Partner of Crosstex Energy, L.P. The General Partner is an indirect wholly owned subsidiary of Crosstex Energy Holdings Inc. The General Partner owns a 2% general partner interest in Crosstex Energy, L.P.

(2) Significant Accounting Policies

(a) Cash and Cash Equivalents

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

(b) Federal Income Taxes

No provision is made in the accounts of the General Partner for federal or state income taxes because such taxes are liabilities of the individual partners, and the amounts thereof depend upon their respective tax situations. The tax returns and amounts of allocable General Partner revenues and expenses are subject to examination by federal and state taxing authorities. If such examinations result in changes to allocable General Partner revenues and expenses, the tax liability of the Partners could be changed accordingly.

(c) Management's Use of Estimates

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

(3) Investment in Crosstex Energy, L.P.

At December 31, 2002 and June 30, 2003, the General Partner's 2% interest in Crosstex Energy, L.P. is the General Partner's only unconsolidated affiliate. The 2% interest is accounted for by the equity method. The following is condensed balance sheet data for Crosstex Energy, L.P. (in thousands):

	December 31, 2002	June 30, 2003
		Unaudited
Assets		
Current assets	$ 110,998	$ 149,722
Property and equipment, net	109,948	188,986
Assets from risk management activities	155	1
Intangible assets, net	5,340	5,847
Goodwill, net	4,873	4,873
Investment in limited partnerships	346	1,113
Other assets, net	778	2,023
Total assets	$ 232,438	$ 352,565
Liabilities and Partners' Equity		
Current liabilities	$ 119,670	$ 160,741
Long-term debt	22,500	98,700
Liabilities from risk management activities	271	20
Liability from interest rate swap	181	323
Partners' equity	89,816	92,781
Total liabilities and partners' equity	$ 232,438	$ 352,565

In the period ended December 31, 2002, Crosstex Energy, L.P. contributed $1,010,000 in equity to the General Partner upon their initial public offering on December 17, 2002. The net income allocated to the General Partner from December 17, 2002 through December 31, 2002 was $6,000 and net income and stock-based compensation allocated for the six months ended June 30, 2003 totaled $233,000.

INDEPENDENT AUDITORS' REPORT

Board of Directors
Duke Energy Field Services, LLC
Denver, Colorado

We have audited the accompanying Statement of Revenues and Direct Operating Expenses (the "Carve-Out Financial Statement") of the Assets, as defined in the purchase and sale agreement between Duke Energy Field Services, L.P. ("DEFS") and Crosstex Energy, L.P. ("Crosstex") dated April 29, 2003 (the "Agreement") for the year ended December 31, 2002. The Carve-Out Financial Statement is the responsibility of DEFS' management. Our responsibility is to express an opinion on the Carve-Out Financial Statement based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the Carve-Out Financial Statement is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the Carve-Out Financial Statement. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the Carve-Out Financial Statement. We believe that our audit provides a reasonable basis for our opinion.

The accompanying Carve-Out Financial Statement was prepared for the purpose of complying with the rules and regulations of the Securities and Exchange Commission (for inclusion in Form S-1 of Crosstex) as described in Note 1 to the Carve-Out Financial Statement and is not intended to be a complete presentation of the Revenues and Direct Operating Expenses of the Assets, as defined in the Agreement.

In our opinion, such Carve-Out Financial Statement presents fairly, in all material respects, the Revenues and Direct Operating Expenses described in Note 1 to the Carve-Out Financial Statement for the year ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Denver, Colorado
June 30, 2003

CERTAIN MID-STREAM ASSETS

OF DUKE ENERGY FIELD SERVICES, L.P.

STATEMENT OF REVENUES AND DIRECT OPERATING EXPENSES

YEAR ENDED DECEMBER 31, 2002 AND SIX MONTHS ENDED

JUNE 30, 2003 AND JUNE 30, 2002

	Year Ended December 31, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
		Unaudited	Unaudited
REVENUES	$ 137,255,152	$ 106,321,913	$ 60,630,800
GAS AND PETROLEUM PURCHASES	(120,966,588)	(97,838,288)	(53,617,230)
Gross margin	16,288,564	8,483,625	7,013,570
DIRECT OPERATING EXPENSES:			
Operating costs	(5,281,663)	(3,097,643)	(2,369,862)
Impairment	(6,899,998)	—	—
Depreciation	(4,277,105)	(1,923,778)	(2,082,657)
Total direct operating expenses	(16,458,766)	(5,021,421)	(4,452,519)
(EXCESS OF DIRECT OPERATING EXPENSES OVER REVENUES) EXCESS OF REVENUES OVER DIRECT OPERATING EXPENSES	$ (170,202)	$ 3,462,204	$ 2,561,051

See notes to Carve-Out Financial Statement.

CERTAIN MID-STREAM ASSETS OF

DUKE ENERGY FIELD SERVICES, L.P.

NOTES TO STATEMENT OF REVENUES AND DIRECT OPERATING EXPENSES

YEAR ENDED DECEMBER 31, 2002 AND

THE SIX MONTHS ENDED JUNE 30, 2003 (UNAUDITED) AND JUNE 30, 2002 (UNAUDITED)

1. BASIS OF PRESENTATION

In April 2003, Crosstex Energy Services, L.P. ("Crosstex") signed an agreement to acquire from Duke Energy Field Services, L.P. ("DEFS") certain mid-stream assets (the "assets"), as defined in the Purchase and Sale Agreement between DEFS and Crosstex dated April 29, 2003 ("the Agreement") for approximately $67.3 million. The acquired assets include a gas processing plant, two pipelines and two gathering systems. The acquired assets also include a 12.4% undivided interest in a gas processing plant, the revenues and expenses of which are reported on a proportionate gross basis. The acquisition closed on June 30, 2003.

The Statement of Revenues and Direct Operating Expenses associated with the assets was derived from DEFS accounting records. Certain expense items not directly associated with the assets, such as interest, income taxes, corporate overhead and hedging activities, were not recorded in the accounting records of the assets. Any allocation of such costs would be arbitrary and would not be indicative of what such costs actually would have been had the asset been operated as a stand-alone entity.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates—Conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the Statement of Revenues and Direct Operating Expenses. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could be different from those estimates.

Revenue Recognition—Revenues are recognized on sales of natural gas and petroleum products in the period of delivery and transportation revenues in the period the services are provided. For gas processing services, cash or commodities are received as payment depending on the type of contract, at the time the processing occurs. Under "percentage-of-proceeds" contracts, fees are paid in the form of a percentage of the recovered natural gas liquids, which are sold into the market. Under "processing fee" contracts, processing fees are paid in the form of cash.

Depreciation—Depreciation is computed using the straight-line method over the estimated useful life of the individual assets.

Gas Imbalance Accounting—Quantities of natural gas over-delivered or under-delivered related to imbalance agreements with producers or pipelines are recorded monthly using then current index prices or the weighted-average prices of natural gas at the plant or system. These balances are settled with cash or deliveries of natural gas.

Impairment of Long-Lived Assets—The recoverability of long-lived assets is reviewed when circumstances indicate that the carrying amount of the asset may not be recoverable, in accordance with Statement of Financial Accounting Standards No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*." The carrying value of a long-lived asset is considered impaired when the anticipated undiscounted cash flow from use of such asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. Fair value is determined primarily using the anticipated

cash flows discounted at a rate commensurate with the risk involved. For the year ended December 31, 2002, an impairment charge of approximately $6.9 million was recorded.

***New Accounting Pronouncement*—**In June 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standard ("SFAS") No. 143, "*Accounting for Asset Retirement Obligations*," which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is increased due to the passage of time based on the time value of money until the obligation is settled. DEFS adopted the provisions of SFAS No. 143 as of January 1, 2003, which did not have a material effect on the Statement of Revenues and Direct Operating Expenses.

3. RELATED PARTY TRANSACTIONS

Revenues include sales, primarily residue gas, totaling approximately $8.1 million, $6.1 million, and $3.1 million for the year ended December 31, 2002, and the six months ended June 30, 2003 and June 30, 2002, respectively, to Duke Energy Trading and Marketing, L.L.C. ("DETM"), an affiliate of DEFS. Gas and petroleum purchases include purchases from DETM of approximately $0.7 million for the year ended December 31, 2002 and were insignificant for the six months ended June 30, 2003 and 2002.

APPENDIX A

Glossary of Terms

adjusted operating surplus: For any period, operating surplus generated during that period is adjusted to:

(a) decrease operating surplus by:

(1) any net increase in working capital borrowings with respect to that period; and

(2) any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made during that period; and

(b) increase operating surplus by:

(1) any net decrease in working capital borrowings with respect to that period; and

(2) any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted operating surplus does not include that portion of operating surplus included in clause (a) (1) or the definition of operating surplus.

available cash: For any quarter ending prior to liquidation:

(a) the sum of

(1) all cash and cash equivalents of Crosstex Energy, L.P. and its subsidiaries on hand at the end of that quarter; and

(2) all additional cash and cash equivalents of Crosstex Energy, L.P. and its subsidiaries on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made after the end of that quarter;

(b) less the amount of cash reserves that is necessary or appropriate in the reasonable discretion of the general partner to

(1) provide for the proper conduct of the business of Crosstex Energy, L.P. and its subsidiaries (including reserves for future capital expenditures and for future credit needs of Crosstex Energy, L.P. and its subsidiaries) after that quarter;

(2) comply with applicable law or any debt instrument or other agreement or obligation to which Crosstex Energy, L.P. or any of its subsidiaries is a party or its assets are subject; and

(3) provide funds for minimum quarterly distributions and cumulative common unit arrearages for any one or more of the next four quarters;

provided, however, that the general partner may not establish cash reserves for distributions to the subordinated units unless the general partner has determined that, in its judgment, the establishment of reserves will not prevent Crosstex Energy, L.P. from distributing the minimum quarterly distribution on all common units and any cumulative common unit arrearages thereon for the next four quarters; and

provided, further, that disbursements made by Crosstex Energy, L.P. or any of its subsidiaries or cash reserves established, increased or reduced after the end of that quarter but on or before the date of determination of available cash for that quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if the general partner so determines.

btu: British Thermal Units.

capital account: The capital account maintained for a partner under the partnership agreement. The capital account of a partner for a common unit, a subordinated unit, or any other partnership interest will be the amount which that capital account would be if that common unit, subordinated unit, incentive distribution right or other partnership interest were the only interest in Crosstex Energy, L.P. held by a partner.

capital surplus: All available cash distributed by us from any source will be treated as distributed from operating surplus until the sum of all available cash distributed since the closing of the initial public offering equals the operating surplus as of the end of the quarter before that distribution. Any excess available cash will be deemed to be capital surplus.

closing price: The last sale price on a day, regular way, or in case no sale takes place on that day, the average of the closing bid and asked prices on that day, regular way. In either case, as reported in the principal consolidated transaction reporting system for securities listed or admitted to trading on the principal national securities exchange on which the units of that class are listed or admitted to trading. If the units of that class are not listed or admitted to trading on any national securities exchange, the last quoted price on that day. If no quoted price exists, the average of the high bid and low asked prices on that day in the over-the-counter market, as reported by the Nasdaq Stock Market or any other system then in use. If on any day the units of that class are not quoted by any organization of that type, the average of the closing bid and asked prices on that day as furnished by a professional market maker making a market in the units of the class selected by the general partner. If on that day no market maker is making a market in the units of that class, the fair value of the units on that day as determined reasonably and in good faith by the general partner.

common unit arrearage: The amount by which the minimum quarterly distribution for a quarter during the subordination period exceeds the distribution of available cash from operating surplus actually made for that quarter on a common unit, cumulative for that quarter and all prior quarters during the subordination period.

current market price: For any class of units listed or admitted to trading on any national securities exchange as of any date, the average of the daily closing prices for the 20 consecutive trading days immediately prior to that date.

gpm: Gallons per minute.

incentive distribution right: A non-voting limited partner partnership interest issued to the general partner in connection with the formation of the partnership. The partnership interest will confer upon its holder only the rights and obligations specifically provided in the partnership agreement for incentive distribution rights.

incentive distributions: The distributions of available cash from operating surplus initially made to the general partner that are in excess of the general partner's aggregate 2% general partner interest.

interim capital transactions: The following transactions if they occur prior to liquidation:

(a) borrowings, refinancings or refundings of indebtedness and sales of debt securities (other than for working capital borrowings and other than for items purchased on open account in the ordinary course of business) by Crosstex Energy, L.P. or any of its subsidiaries;

(b) sales of equity interests by Crosstex Energy, L.P. or any of its subsidiaries;

(c) sales or other voluntary or involuntary dispositions of any assets of Crosstex Energy, L.P. or any of its subsidiaries (other than sales or other dispositions of inventory, accounts receivable

and other assets in the ordinary course of business, and sales or other dispositions of assets as a part of normal retirements or replacements).

MMBtu: One million British Thermal Units.

Mcf: One thousand cubic feet of natural gas.

Mcf/d: One thousand cubic feet per day.

Mmcf: One million cubic feet of natural gas.

MMBtu/d: One million British Thermal Units per day.

Mmcf/d: One million cubic feet per day.

NGLs: Natural gas liquids which consist primarily of ethane, propane, isobutane, normal butane and natural gas.

operating expenditures: All expenditures of Crosstex Energy, L.P. and our subsidiaries, including, but not limited to, taxes, reimbursements of the general partner, repayment of working capital borrowings, debt service payments and capital expenditures, subject to the following:

(a) Payments (including prepayments) of principal of and premium on indebtedness, other than working capital borrowings will not constitute operating expenditures.

(b) Operating expenditures will not include:

(1) capital expenditures made for acquisitions or for capital improvements;

(2) payment of transaction expenses relating to interim capital transactions; or

(3) distributions to partners.

operating surplus: For any period prior to liquidation, on a cumulative basis and without duplication:

(a) the sum of

(1) $8.9 million plus all the cash of Crosstex Energy, L.P. and its subsidiaries on hand as of the closing date of our initial public offering;

(2) all cash receipts of Crosstex Energy, L.P. and our subsidiaries for the period beginning on the closing date of our initial public offering and ending with the last day of that period, other than cash receipts from interim capital transactions; and

(3) all cash receipts of Crosstex Energy, L.P. and our subsidiaries after the end of that period but on or before the date of determination of operating surplus for the period resulting from working capital borrowings; less

(b) the sum of:

(1) operating expenditures for the period beginning on the closing date of our initial public offering and ending with the last day of that period; and

(2) the amount of cash reserves that is necessary or advisable in the reasonable discretion of the general partner to provide funds for future operating expenditures; provided however, that disbursements made (including contributions to a member of Crosstex Energy, L.P. and our subsidiaries or disbursements on behalf of a member of Crosstex Energy, L.P.

and our subsidiaries) or cash reserves established, increased or reduced after the end of that period but on or before the date of determination of available cash for that period shall be deemed to have been made, established, increased or reduced for purposes of determining operating surplus, within that period if the general partner so determines.

subordination period: The subordination period will generally extend from the closing of the initial public offering until the first to occur of:

(a) the first day of any quarter on or after December 31, 2007 for which:

(1) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the sum of the minimum quarterly distribution on all of the outstanding common units and subordinated units for each of the three consecutive non-overlapping four-quarter periods immediately preceding that date;

(2) the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distribution on all of the common units and subordinated units that were outstanding during those periods on a fully-diluted basis, and the related distribution on the general partner interests in Crosstex Energy, L.P.; and

(3) there are no outstanding cumulative common units arrearages.

(b) the date on which the general partner is removed as general partner of Crosstex Energy, L.P. upon the requisite vote by the limited partners under circumstances where cause does not exist and units held by the general partner and its affiliates are not voted in favor of the removal.

throughput: The volume of gas transported or passing through a pipeline or other facility.

units: refers to both common units and subordinated units, but not the general partner interest.

working capital borrowings: Borrowings exclusively for working capital purposes made pursuant to a credit facility or other arrangement requiring all borrowings thereunder to be reduced to a relatively small amount each year for an economically meaningful period of time.

You may rely on the information contained in this prospectus. We have not authorized anyone to provide information different from that contained in this prospectus. Neither the delivery of this prospectus nor sale of common units means that information contained in this prospectus is correct after the date of this prospectus. This prospectus is not an offer to sell or solicitation of an offer to buy these common units in any circumstances under which the offer or solicitation is unlawful.

TABLE OF CONTENTS

1,500,000 Common Units

Crosstex Energy, L.P.
Representing
Limited Partner Interests

PROSPECTUS

A.G. Edwards & Sons, Inc.
RBC Capital Markets
Raymond James

September 3, 2003