SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended June 30, 2005

or

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

For the transition period from to

Commission file number: 000-50067

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

Delaware *(State of organization)*	**16-1616605** *(I.R.S. Employer Identification No.)*
2501 Cedar Springs **Dallas, Texas** *(Address of principal executive offices)*	**75201** *(Zip Code)*

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

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

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

As of July 31, 2005, the Registrant had 8,817,646 common units, 9,334,000 subordinated units and 1,495,410 senior subordinated units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	June 30, 2005	December 31, 2004
	(Unaudited) (In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,329	$ 5,797
Accounts and notes receivable:		
Trade, accrued revenue, and other, net of allowance for bad debt of $260 and $60, respectively	221,511	233,777
Related party	274	486
Fair value of derivative assets	2,659	3,025
Prepaid expenses, natural gas in storage and other	6,907	5,077
Total current assets	233,680	248,162
Property and equipment, net of accumulated depreciation of $59,200 and $45,090, respectively	350,689	324,730
Fair value of derivatives assets	1,127	166
Intangible assets, net of accumulated amortization of $3,650 and $3,301, respectively	5,153	5,155
Goodwill	6,210	4,873
Other assets, net	4,160	3,685
Total assets	$ 601,019	$ 586,771
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts, drafts payable and accrued gas purchases	$ 231,654	$ 257,746
Fair value of derivative liabilities	5,144	2,085
Current portion of long-term debt	1,815	50
Other current liabilities	16,364	23,005
Total current liabilities	254,977	282,886
Fair value of derivative liabilities	1,076	134
Long-term debt	150,835	148,650
Deferred tax liability	7,815	8,005
Minority interest in subsidiary	4,558	3,046
Partners' equity	181,758	144,050
Total liabilities and partners' equity	$ 601,019	$ 586,771

See accompanying notes to consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(Unaudited) (In thousands, except per unit amounts)			
Revenues:				
Midstream	$ 619,432	$ 507,744	$ 1,158,996	$ 825,957
Treating	11,040	7,568	20,947	14,712
Profit on energy trading activities	399	826	444	1,246
Total revenues	630,871	516,138	1,180,387	841,915
Operating costs and expenses:				
Midstream purchased gas	594,482	485,212	1,110,898	788,088
Treating purchased gas	1,711	1,487	3,204	2,863
Operating expenses	12,178	10,366	23,722	16,630
General and administrative	7,750	4,960	14,211	8,709
(Gain) loss on sale of property	(120)	(22)	(164)	274
Depreciation and amortization	7,370	5,921	14,306	10,339
Total operating costs and expenses	623,371	507,924	1,166,177	826,903
Operating income	7,500	8,214	14,210	15,012
Other income (expense):				
Interest expense, net	(3,196)	(2,186)	(6,561)	(3,341)
Other	322	112	348	204
Total other income (expense)	(2,874)	(2,074)	(6,213)	(3,137)
Income before minority interest and taxes	4,626	6,140	7,997	11,875
Minority interest in subsidiary	(88)	(70)	(225)	(99)
Income tax provision	(54)	(129)	(108)	(129)
Net income	$ 4,484	$ 5,941	$ 7,664	$ 11,647
General partner interest in net income	$ 1,205	$ 1,393	$ 3,226	$ 2,442
Limited partners' interest in net income	$ 3,279	$ 4,548	$ 4,438	$ 9,205
Net income per limited partners' unit:				
Basic	$ 0.18	$ 0.25	$ 0.25	$ 0.51
Diluted	$ 0.17	$ 0.24	$ 0.24	$ 0.48
Weighted average limited partners' units outstanding:				
Basic	18,124	18,081	18,111	18,077
Diluted	18,880	19,156	18,819	19,122

See accompanying notes to consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Six Months ended June 30, 2005

(Unaudited)
(In thousands, except unit amounts)

	Common Units		Subordinated Units		Senior Subordinated Units		General Partner Interest		Accumulated Other Comprehensive Income	Total
	$	Units	$	Units	$	Units	$	Units		
Balance, December 31, 2004	$ 111,960	8,755,066	$ 28,002	9,334,000	—	—	$ 4,078	369,000	$ 10	$ 144,050
Proceeds from exercise of unit options	562	48,763	—	—	—	—	—	—	—	562
Net proceeds from issuance of senior subordinated units	—	—	—	—	49,950	1,495,410	—	—	—	49,950
Common units for restricted units	—	2,150	—	—	—	—	—	—	—	—
Capital contributions	—	—	—	—	—	—	1,528	31,722	—	1,528
Stock-based compensation	228	—	241	—	—	—	661	—	—	1,130
Distributions	(7,986)	—	(8,494)	—	—	—	(4,236)	—	—	(20,716)
Net income	2,152	—	2,286	—	—	—	3,226	—	—	7,664
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	882	882
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	(3,292)	(3,292)
Balance, June 30, 2005	$ 106,916	8,805,979	$ 22,035	9,334,000	$ 49,950	1,495,410	$ 5,257	400,722	$ (2,400)	$ 181,758

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(Unaudited) (In thousands)	
Net income	$ 7,664	$ 11,647
Hedging gains or losses reclassified to earnings	882	(1,395)
Adjustment in fair value of derivatives	(3,292)	4,167
Comprehensive income	$ 5,254	$ 14,419

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income	$ 7,664	$ 11,647
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	14,306	10,339
Loss on investment in affiliated partnerships	—	(200)
Non-cash stock-based compensation	1,130	478
(Gain) loss on sale of property	(164)	274
Deferred tax benefit	(190)	—
Minority interest in subsidiary	225	99
Changes in assets and liabilities, net of acquisition effects:		
Accounts receivable, accrued revenue, and other	12,659	(35,533)
Prepaid expenses	(1,830)	(2,533)
Accounts payable, accrued gas purchases, and other accrued liabilities	(20,039)	39,758
Fair value of derivatives	996	179
Other	561	424
Net cash provided by operating activities	15,318	24,932
Cash flows from investing activities:		
Additions to property and equipment	(25,780)	(15,284)
Assets acquired	(15,969)	(73,158)
Proceeds from sale of property	313	226
Distributions from (investment in) affiliated partnerships	—	(48)
Net cash used in investing activities	(41,436)	(88,264)
Cash flows from financing activities:		
Proceeds from borrowings	457,750	276,000
Payments on borrowings	(453,800)	(212,050)
Increase (decrease) in drafts payable	(12,694)	16,537
Proceeds from issuance of senior subordinated units	49,950	—
Capital contributions	1,528	—
Contributions from minority interest	1,287	—
Distribution to partners	(20,716)	(15,800)
Proceeds from exercise of unit options	562	308
Debt issuance costs	(1,217)	(1,091)
Net cash provided by financing activities	22,650	63,904
Net increase (decrease) in cash and cash equivalents	(3,468)	572
Cash and cash equivalents, beginning of period	5,797	166
Cash and cash equivalents, end of period	$ 2,329	$ 738
Cash paid for interest	$ 6,096	$ 2,778

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements
June 30, 2005
(Unaudited)

(1) General

Unless the context requires otherwise, references to "we","us","our" or the "Partnership" mean Crosstex Energy, L.P. and its consolidated subsidiaries.

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 to its gathering systems 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.

The accompanying consolidated financial statements are prepared in accordance with the instructions to Form 10-Q, are unaudited and do not include all the information and disclosures required by generally accepted accounting principles for complete financial statements. All adjustments that, in the opinion of management, are necessary for a fair presentation of the results of operations for the interim periods have been made and are of a recurring nature unless otherwise disclosed herein. The results of operations for such interim periods are not necessarily indicative of results of operations for a full year. All significant intercompany balances and transactions have been eliminated in consolidation. These consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our restated annual report on Form 10-K for the year ended December 31, 2004. Certain reclassifications have been made to the consolidated financial statements for the prior year periods to conform to the current presentation.

(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) Long-Term Incentive Plans

The Partnership applies the provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), and the related interpretations in accounting for the long-term incentive plans. In accordance with APB No. 25 for fixed stock and unit options, compensation is recorded to the extent the fair value of the stock or unit exceeds the exercise price of the option at the measurement date. Compensation costs for fixed awards with pro rata vesting are recognized on a straight-line basis over the vesting period. In addition, compensation expense is recorded for variable options based on the difference between fair value of the stock or unit and the exercise price of the options at period end for unexercised variable options. Certain fixed awards were modified during 2005 to accelerate vesting resulting in compensation expense of $513,000 based on the difference between the fair value of the stock or units at the date of acceleration and the exercise price of the options.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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 would have been as follows (in thousands, except per unit amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Net income, as reported	$ 4,484	$ 5,941	$ 7,664	$ 11,647
Add: Stock-based employee compensation expense included in reported net income	1,241	269	1,515	478
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(1,223)	(317)	(1,628)	(580)
Pro forma net income	$ 4,502	$ 5,893	$ 7,551	$ 11,545
Net income per limited partner unit, as reported:				
Basic	$ 0.18	$ 0.25	$ 0.25	$ 0.51
Diluted	$ 0.17	$ 0.24	$ 0.24	$ 0.48
Pro forma net income per limited partner unit:				
Basic	$ 0.18	$ 0.25	$ 0.24	$ 0.50
Diluted	$ 0.18	$ 0.23	$ 0.23	$ 0.48

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 Partnership unit grants in the six months ended June 30, 2005:

	2005
Options granted	175,880
Weighted average dividend yield	5.0%
Weighted average expected volatility	33.0%
Weighted average risk-free interest rate	3.7%
Weighted average expected life (years)	3
Contractual life (years)	10
Weighted average of fair value of unit options granted	$ 7.93

The exercise price for 174,049 unit options granted in June 2005 was based on the market value of the units on January 1, 2005 which was less than the market value of the date of grant. The market value in excess of the exercise price totaling $776,000 is amortized into stock-based compensation ratably over the 3-year vesting period.

No Crosstex Energy, Inc. (CEI) options were granted to officers or employees of the Partnership in 2005. Stock-based compensation associated with the CEI long-term incentive plan with respect to officers and employees is recorded by the Partnership since CEI has no operating activities, other than its interest in the Partnership.

In June 2005, the Partnership issued 111,552 restricted units to senior management and employees under its long-term incentive plan with an intrinsic value of $4,145,000. CEI issued 86,762 restricted common shares to senior management and employees of the Partnership with an intrinsic value of $3,880,000. These restricted units and CEI restricted common shares vest on January 1, 2008, and the intrinsic value of the restricted units and restricted common shares is amortized into stock-based compensation ratably over the vesting periods.

Unit distributions paid on the restricted units prior to vesting are considered cash compensation expense and are charged to general and administrative expense.

Stock-based compensation expense totaled $1,239,000 and $1,515,000 for the three and six months ended June 30, 2005, respectively, as described in more detail below, and is included in general and administrative expenses ($1,078,000 and $1,307,000 for the respective three- and six-month periods) and in operating expenses ($161,000 and $208,000 for the respective three- and six-month periods). Stock-based compensation expense of $80,000 and $156,000 was recognized during the three and six months ended June 30, 2005, respectively, related to amortization of unit and stock options. Stock-based compensation expense of $513,000 was recognized in the three months ended June 30, 2005 related to the accelerated vesting of 7,060 unit options and 10,000 CEI common share options. Stock-based compensation expense of $261,000 and $461,000 was recognized during the three and six months ended June 30, 2005, respectively, related to the amortization of restricted units and CEI restricted common shares. Stock-based compensation expense also includes $385,000 of payroll taxes associated with CEI stock option exercises and CEI contributed capital for the same amount to reimburse the Partnership for these taxes.

In May 2005, the Partnership's managing general partner amended the Partnership's long-term incentive plan to increase the aggregate common unit options and restricted units under the plan from 1.4 million to 1.8 million.

(c) 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 three and six months ended June 30, 2005 and 2004. The computation of diluted earnings per unit further assumes the dilutive effect of unit options, restricted units and senior subordinated units.

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

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and six months ended June 30, 2005 and 2004 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Basic earnings per unit:				
Weighted average limited partner units outstanding	18,124	18,081	18,111	18,077
Diluted earnings per unit:				
Weighted average limited partner units outstanding	18,124	18,081	18,111	18,077
Dilutive effect of restricted units issued	105	—	102	—
Dilutive effect of senior subordinated units	100	—	50	—
Dilutive effect of exercise of options outstanding	551	1,075	556	1,045
Diluted units	18,880	19,156	18,819	19,122

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

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note (4). In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to CEI stock options and restricted stock all to the general partner to match the related general partner contribution for such items. Therefore, beginning in the second quarter of 2005, the general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units, and the common units. The net income allocated to the general partner for incentive distributions was $2,175,000 and $1,301,000 for the three months ended June 30, 2005 and 2004, respectively, and $4,173,000 and $2,254,000 for the six months ended June 30, 2005 and 2004, respectively. Stock-based compensation related to CEI options and restricted stock was $1.0 million for the six months ended June 30, 2005.

(d) New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123 (Revised 2004), *Share-Based Payment* (SFAS No. 123R), which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements. This pronouncement replaces SFAS No. 123, *Accounting for Stock-Based Compensation,* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees* and will be effective beginning January 1, 2006. We have previously recorded stock compensation pursuant to the intrinsic value method under APB No. 25, whereby no compensation was recognized for most stock option awards. We expect that stock option grants will continue to be a significant part of employee compensation, and therefore, SFAS No. 123R will impact our financial statements. We reviewed the impact of SFAS No. 123R and we believe that the pro forma effect of recording compensation for all stock awards at fair value utilizing the Black-Scholes method for the three and six months ended June 30, 2005 and 2004 presented in Note 1(b) above is not materially different.

In March 2005, the FASB issued Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations"* (FIN 47). FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, *"Accounting for Asset Retirement Obligations"*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FIN 47 provides that a liability for the fair value of a conditional asset retirement obligation should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB Statement No. 143. FIN 47 is effective for fiscal years ending after December 15, 2005, and is not expected to affect the Partnership's financial position or results of operations.

(2) Significant Acquisition

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

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

	Six Months Ended June 30, 2004
Revenue	$ 1,075,248
Net income	$ 10,287
Net income per limited partner unit	
Basic	$ 0.44
Diluted	$ 0.41
Weighted average limited partners' units outstanding	
Basic	18,077
Diluted	19,122

(3) Long-Term Debt

As of June 30, 2005 and December 31, 2004, long-term debt consisted of the following (in thousands):

	June 30, 2005	December 31, 2004
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at June 30, 2005 and December 31, 2004 were 5.34% and 4.99%, respectively	$ 37,000	$ 33,000
Senior secured notes, weighted average interest rate of 6.95%	115,000	115,000
Note payable to Florida Gas Transmission Company	650	700
	152,650	148,700
Less current portion	(1,815)	(50)
Debt classified as long-term	$ 150,835	$ 148,650

On March 31, 2005, the Partnership amended the bank credit facility, increasing availability under the facility to $250 million, eliminating the distinction between an acquisition and working capital facility and extending the maturity date from June 2006 to March 2010. Additionally, an accordion feature built into the credit facility allows the Partnership to increase the availability to $350 million.

In June 2005, the Partnership amended the shelf agreement governing the senior secured notes to increase its availability from $125 million to $200 million.

(4) Partners' Capital

Issuance of Senior Subordinated Units

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

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. Distributions will generally be made 98% to the common and subordinated unitholders (other than the senior subordinated unitholders) and 2% to the general partner, subject to the payment of incentive distributions to the extent that certain target levels of cash distributions are achieved. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $2,175,000 and $4,173,000 were earned by our general partner for the three months and six months ended June 30, 2005, respectively. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The Partnership has declared a second quarter 2005 distribution of $0.47 per unit to be paid on August 15, 2005.

(5) Derivatives

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and to hedge prices and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

The Partnership commonly enters into various derivative financial transactions which it does not designate as hedges. These transactions include “swing swaps”, “third party on-system financial swaps”, “marketing financial swaps”, and “storage swaps”. Swing swaps are generally short-term in nature (one month), and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers, and simultaneously enters into the derivative transaction. Marketing financial swaps are similar to on-system financial swaps, but are entered into for customers not connected to the Partnership’s systems. Storage swaps transactions protect against changes in the value of gas that the Partnership has stored to serve various operational requirements.

The components of profit on energy trading activities in the Consolidated Statements of Operations are (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Commercial services margin	$ 323	$ 810	$ 753	$ 1,157
Change in fair value of derivates that do not qualify for hedge accounting	156	16	(432)	89
Ineffective portion of derivatives qualifying for hedge accounting	(80)	—	123	—
	$ 399	$ 826	$ 444	$ 1,246

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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

	June 30, 2005	December 31, 2004
Fair value of derivative assets — current	$ 2,659	$ 3,025
Fair value of derivative assets — long term	1,127	166
Fair value of derivative liabilities — current	(5,144)	(2,085)
Fair value of derivative liabilities — long term	(1,076)	(134)
Net fair value of derivatives	$ (2,434)	$ 972

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at June 30, 2005 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than December 2007, with no single contract longer than six months. The Partnership's counterparties to hedging contracts include BP Corporation, UBS Energy and Total Gas & Power. Changes in the fair value of the Partnership's derivatives related to third party producers and customers' gas marketing activities are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings and the ineffective portion is recorded in earnings.

June 30, 2005

Transaction type	Total volume	Pricing terms	Remaining term of contracts	Fair value (in thousands)
Cash Flow Hedges:				
Natural gas swaps	3,690,000	NYMEX plus a basis of $0.05 to NYMEX flat or fixed prices ranging	July 2005 – October 2005	$ (11)
Natural gas swaps	(2,670,000)	from $5.66 to $7.565 settling against various Inside FERC Index prices	July 2005 – June 2006	(2,014)
Total natural gas swaps designated as cash flow hedges				$ (2,025)
Liquids swaps	(4,508,406)	Fixed prices ranging from $0.48 to $1.155 settling against Mt. Belvieu Average of daily postings (non-TET)	July 2005 – December 2005	$ (251)
Total liquids swaps designated as cash flow hedges				$ (251)
Mark to Market Derivatives:				
Swing swaps	308,326	Prices ranging from Inside FERC Index plus $0.015 to Inside FERC	July 2005	$ —
Swing swaps	(652,705)	Index less $0.01 settling against various Inside FERC Index prices	July 2005	(7)
Total swing swaps				$ (7)

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

June 30, 2005				
Transaction type	**Total volume**	**Pricing terms**	**Remaining term of contracts**	**Fair value (in thousands)**
Physical offset to swing swap transactions	652,705	Prices of various Inside FERC Index prices settling against	July 2005	—
Physical offset to swing swap transactions	(308,326)	various Inside FERC Index prices	July 2005	—
Total physical offset to swing swaps				$ —
Third party on-system financial swaps	3,458,000	Fixed prices ranging from $5.659 to $8.00 settling	July 2005 – December 2007	$ 2,526
Third party on-system financial swaps	(733,000)	against various Inside FERC Index prices	July 2005 – March 2006	(232)
Total third party on-system financial swaps				$ 2,294
Physical offset to third party on-system transactions	733,000	Fixed prices ranging from $5.71 to $8.225 settling against various Inside	July 2005 – March 2006	$ 258
Physical offset to third party on-system transactions	(3,458,000)	FERC Index prices	July 2005 – December 2007	(2,353)
Total physical offset to third party on-system swaps				$ (2,095)
Marketing trading financial swaps	(800,000)	Fixed prices ranging from $6.50 to $7.35 settling against various Inside FERC Index prices	July 2005 – March 2006	$ (625)
Marketing trading financial swaps	40,000		July 2005	11
Total marketing trading financial swaps				$ (614)
Physical offset to marketing trading transactions	800,000	Fixed prices ranging from $6.45 to $7.30 settling against various Inside FERC Index prices	July 2005 – March 2006	$ 665
Physical offset to marketing trading transactions	(40,000)		July 2005	(11)
Total physical offset to marketing trading transactions swaps				$ 654
Storage swap transactions:				
Storage swap transactions	(355,000)	Fixed prices ranging from $6.37 to $8.01 settling against various Inside FERC Index prices	August 2005 – January 2006	$ (390)
Total financial storage swap transactions				$ (390)

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits, and monitors the appropriateness of these limits on an ongoing basis.

Impact of Cash Flow Hedges

Natural Gas

In the first six months of 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $0.3 million. In the first six months of 2004, net losses on futures and basis swap hedge contracts decreased gas revenue by $0.4 million. As of June 30, 2005, an unrealized pre-tax derivative fair value loss of $2.0 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). This entire fair value loss is expected to be reclassified into earnings through June 2006. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date.

The settlement of futures contracts and basis swap agreements related to July 2005 gas production reduced gas revenue by approximately $0.1 million.

Liquids

In the first six months of 2005, net losses on liquids swap hedge contracts decreased liquids revenue by approximately $50,000. As of June 30, 2005, an unrealized pre-tax derivative fair value loss of $0.2 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). This entire fair value loss is expected to be reclassified into earnings in 2005. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date.

Assets and liabilities related to third party derivative contracts, swing swaps and storage swaps are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as profit (loss) on energy trading activities along with the net operating results from Producer Services in the consolidated statement of operations. 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
June 30, 2005	$ (209)	33	18	$ (158)

(6) Transactions with Related Parties

Camden Resources, Inc.

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden). Camden is an affiliate of the Partnership by way of equity investments made in Camden by Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P., collectively the major shareholder in CEI. During the three months ended June 30, 2005 and 2004, the Partnership purchased natural gas from Camden in the amount of approximately $11.5 million and $10 million, respectively, and received approximately $644,000 and $571,000 in treating fees from Camden. The Partnership purchased natural gas from Camden in the amount of approximately $20.7 million and $18.2 million for the six months ended June 30, 2005 and 2004, respectively, and received approximately $1.3 million and $1.2 million, respectively, in treating fees from Camden.

Crosstex Pipeline Partners, L.P.

The Partnership had related-party transactions with Crosstex Pipeline Partners, L.P. (CPP), as summarized below:

- During the three months ended June 30, 2004, the Partnership bought natural gas from CPP in the amount of approximately $2.7 million and paid for transportation of approximately $10,400 to CPP. During the six months ended June 30, 2004, the Partnership bought natural gas from CPP in the amount of approximately $4.9 million and paid for transportation of approximately $22,000 to CPP.

- During the three months ended June 30, 2004, the Partnership received a management fee from CPP of $31,000. During the six months ended June 30, 2004, the Partnership received a management fee from CPP of $63,000.

- During the three months ended June 30, 2004, the Partnership received distributions from CPP in the amount of approximately $30,000. During the six months ended June 30, 2004, the Partnership received distributions from CPP in the amount of approximately $51,000.

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

(7) Commitments and Contingencies

(a) Employment Agreements

Each member of senior management of the Partnership is a party to an employment contract 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.

(b) Environmental Issues

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

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

(c) Other

In March and June 2005, the Partnership received deposits totaling $3.6 million pursuant to a contract to sell an idle processing plant for $9 million. The sale is expected to close no later than September 2005. The deposits are recorded as a liability in the accompanying consolidated financial statements. Since the Partnership's carrying value for this idle plant is only $0.5 million, the Partnership expects to recognize a gain of approximately $8.5 million upon closing.

In May 2003, four landowner groups filed suit against us in the 267th Judicial District Court in Victoria County, Texas seeking damages related to the expiration of an easement for a segment of one of our pipelines located in Victoria County, Texas. In 1963, the original owners of the land granted an easement for a term of 35 years, and the prior owner of the pipeline failed to renew the easement. The Partnership filed a condemnation counterclaim in the district court suit and it filed, in a separate action in the county court, a condemnation suit seeking to condemn a 1.38-mile long easement across the land. Pursuant to condemnation procedures under the Texas Property Code, three special commissioners were appointed to hold a hearing to determine the amount of the landowner's damages. In August 2004, a hearing was held and the special commissioners awarded damages to the current landowners in the amount of $877,500. The Partnership has timely objected to the award of the special commissioners and the condemnation case will now be tried in the county court. The damages awarded by the special commissioners will have no effect on and cannot be introduced as evidence in the trial. The county court will determine the amount that the Partnership will pay the current landowners for an easement across their land and will determine whether or not and to what extent the current landowners are entitled to recover any damages for the time period that there was not an easement for the pipeline on their land. Under the Texas Property Code, in order to maintain possession of and continued use of the pipeline until the matter has been resolved in the county court, the Partnership was required to post bonds and cash, each totaling the amount of $877,500, which is the amount of the special commissioners award. The deposit of $877,500 is reflected in current assets as of June 30, 2005. The Partnership is not able to predict the ultimate outcome of this matter.

(8) Segment Information

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

The Partnership evaluates the performance of its operating segments based on earnings before income taxes and accounting changes, and after an allocation of corporate expenses. Corporate expenses are allocated to the segments on a pro rata basis based on the number of employees within the segments. Interest expense is allocated on a pro rata basis based on segment assets. Inter-segment sales are at cost. The 2004 segment data information has been adjusted to conform to these allocation methods.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

Summarized financial information concerning the Partnership’s reportable segments is shown in the following table. The information includes all significant non-cash items.

	Midstream	Treating	Totals
		(In thousands)	
Three months ended June 30, 2005:			
Sales to external customers	$ 619,432	$ 11,040	$ 630,472
Inter-segment sales	2,279	(2,279)	—
Interest expense, net	2,471	725	3,196
Depreciation and amortization	4,747	2,623	7,370
Segment profit	3,578	1,048	4,626
Segment assets	479,089	121,930	601,019
Capital expenditures	7,585	6,158	13,743
Three months ended June 30, 2004:			
Sales to external customers	$ 507,744	$ 7,568	$ 515,312
Inter-segment sales	1,415	(1,415)	—
Interest expense, net	1,883	303	2,186
Depreciation and amortization	4,704	1,217	5,921
Segment profit	4,626	1,315	5,941
Segment assets	477,514	76,787	554,301
Capital expenditures	2,394	5,327	7,721
Six months ended June 30, 2005:			
Sales to external customers	$ 1,158,996	$ 20,947	$ 1,179,943
Inter-segment sales	3,903	(3,903)	—
Interest expense, net	5,226	1,335	6,561
Depreciation and amortization	9,344	4,962	14,306
Segment profit	5,793	2,204	7,977
Segment assets	479,089	121,930	601,019
Capital expenditures	13,014	12,766	25,780
Six months ended June 30, 2004:			
Sales to external customers	$ 825,957	$ 14,712	$ 840,669
Inter-segment sales	2,838	(2,838)	—
Interest expense, net	2,878	463	3,341
Depreciation and amortization	8,264	2,075	10,339
Segment profit	8,481	3,166	11,647
Segment assets	477,514	76,787	554,301
Capital expenditures	6,741	9,031	15,772

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report.

Overview

We are a Delaware limited partnership formed by Crosstex Energy, Inc. (CEI) on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast and in Mississippi and Louisiana. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas, 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, 2005, 73% of our gross margin was generated in the Midstream division with the balance in the Treating division. We manage our business by focusing on gross margin because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas for a fee. We buy and sell most of our gas at a fixed relationship to the relevant index price so our margins are not significantly affected by changes in gas prices. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

Since the formation of our predecessor, we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2000 through June 30, 2005, we have invested over $380 million to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our 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 as well as fees earned from recovering carbon dioxide and natural gas liquids at a non-operated processing plant. We generate revenues from five primary sources:

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

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 or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. See "Commodity Price Risk" below for a discussion of how we manage our business to reduce the impact of price volatility.

We generate commercial 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 41 independent producers. We engage in such activities on more than 20 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 51% and 55% of the operating income in our Treating division for the six months ended June 30, 2005 and 2004, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 40% of the operating income in our Treating division for the six months ended June 30, 2005 and 2004; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 9% and 5% of the operating income in our Treating division for the six months ended June 30, 2005 and 2004, respectively.

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

We 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 purchase since January 2004 was the acquisition of LIG Pipeline Company.

In April 2004 we acquired LIG Pipeline Company and its subsidiaries, which we collectively refer to as LIG, from a subsidiary of American Electric Power for $73.7 million in cash. The principal assets acquired consist of approximately 2,000 miles of gas gathering and transmission systems located in 32 parishes extending from northwest and north-central Louisiana through the center of the state to the south and southeast Louisiana and five processing plants, three of which are currently idle, that straddle the pipeline in three locations and have a total processing capability of 663,000 MMbtu/d. The system has a throughput capacity of 900,000 MMbtu/d and average throughput at the time of our acquisition was approximately 560,000 MMbtu/d. Customers include power plants, municipal gas systems and industrial markets located principally in the industrial corridor between New Orleans and Baton Rouge. The LIG system is connected to several interconnected pipelines and the Jefferson Island Storage facility which provides access to additional system supply. We financed the LIG acquisition through borrowings under our bank credit facility.

In December 2004 we acquired all of the outside limited and general partner interests of Crosstex Pipeline Partners, L.P., or CPP, for $5.1 million. This acquisition made us the sole limited partner and general partner of CPP, so we began consolidating our investment in CPP effective December 31, 2004.

On January 2, 2005 we acquired all of the assets of Graco Operations for $9.25 million. Graco’s assets consisted of 26 treating plants and associated inventory. On May 1, 2005 we acquired all of the assets of Cardinal Gas Services for $6.7 million. Cardinal’s assets consisted of nine gas treating plants, 19 operating wellhead gas processing plants for dewpoint suppression, and equipment inventory.

In March 2005, we entered into a contract to sell an idle processing plant for $9.0 million. We received deposits totaling $3.6 million in March and June 2005 pursuant to this contract. The sale is expected to close no later than September 2005. Since our carrying value for this idle plant is only $0.5 million, we expect to recognize a gain of approximately $8.5 million upon closing.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(Dollars in millions)			
Midstream revenues	$ 619.4	$ 507.7	$ 1,159.0	$ 826.0
Midstream purchased gas	594.4	485.2	1,111.0	788.1
Midstream gross margin	25.0	22.5	48.0	37.9
Treating revenues	11.0	7.6	20.9	14.7
Treating purchased gas	1.7	1.5	3.2	2.9
Treating gross margin	9.3	6.1	17.7	11.8
Total gross margin	$ 34.3	$ 28.6	$ 65.7	$ 49.7
Midstream Volumes (MMBtu/d):				
Gathering and transportation	1,288,000	1,248,000	1,281,000	1,255,000
Processing	486,000	390,000	448,000	405,000
Producer services	194,000	166,000	185,000	181,000
Plants in service at end of period	100	62	100	62

Three Months Ended June 30, 2005 Compared to Three Months Ended June 30, 2004

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $25.0 million for the three months ended June 30, 2005 compared to $22.5 million for the three months ended June 30, 2004, an increase of $2.5 million, or 10.7%. The majority of this increase was due to volume increases at the Plaquemine plant and on the Vanderbilt system which contributed gross margin growth of $1.8 million and $0.9 million, respectively. In addition, a measurement adjustment on the Gregory Gathering system resulted in a $0.9 million increase in gross margin for the 2005 second quarter. These increases were partially offset by a $0.8 million increase in cost of gas due to a physical gas leak.

During the first quarter and into part of April we experienced a line leak in a six-inch lateral to one of our transmission pipelines in a remote and uninhabited area. As a result of the leak a total of 275,000 MMbtu was vented to the atmosphere. The total financial impact of the commodity loss is estimated at $1.9 million, of which $1.1 and $0.8 million was recognized in the first and second quarters of 2005, respectively. We are in the process of expanding our automated monitoring system on all of our pipelines that are not currently equipped with these devices. We believe that this type of monitoring system would have detected the leak much sooner and mitigated the amount of gas vented to the atmosphere. The line has been repaired and was back in service in April 2005.

Treating gross margin was $9.3 million for the three months ended June 30, 2005 compared to $6.1 million in the same period in 2004, an increase of $3.2 million, or 53.4%. The increase in treating plants in service from 62 plants at June 30, 2004 to 100 plants at June 30, 2005 contributed approximately $2.2 million in gross margin. Existing plant assets contributed $0.5 million in gross margin growth due primarily to plant expansion projects and increased volumes. Also contributing to the increase was $0.3 million gross margin improvement from the Seminole plant due to an increase in volumes, fees and higher liquid prices.

Profit on energy trading activity decreased from a profit of $0.8 million for the three months ended June 30, 2004 to a profit of $0.4 million for the three months ended June 30, 2005. Energy trading activity included approximately $0.3 million and $0.8 million of net profit related to our Commercial Services activities during the second quarters of 2005 and 2004, respectively. The second quarter of 2005 includes a $0.2 million gain associated with derivatives for third party on-system financial transactions and storage financial transactions that are considered energy trading activities. We also recognized losses due to the ineffectiveness of certain cash flow hedges of $0.1 million in the second quarter of 2005.

Operating Expenses. Operating expenses were $12.2 million for the three months ended June 30, 2005 compared to $10.4 million for the three months ended June 30, 2004, an increase of $1.8 million, or 17.5%. The growth in treating plants in service increased operating expenses by $0.9 million. Midstream operating expenses increased by $0.7 million due to the Arkoma expansion and additional expenses on the LIG properties. Operating expenses included $0.2 million of stock-based compensation expense for the three months ended June 30, 2005 compared to $0.1 million of stock-based compensation expense for the three months ended June 30, 2004.

General and Administrative Expenses. General and administrative expenses were $7.8 million for the three months ended June 30, 2005 compared to $5.0 million for the three months ended June 30, 2004, an increase of $2.8 million, or 56.3%. The increase was primarily due to increases in staffing associated with the requirements of the LIG acquisition of $1.3 million, the write-off of unsuccessful transaction costs of $0.4 million and the recognition of a bad debt reserve of $0.2 million. General and administrative expenses included $1.1 million of stock-based compensation expense for the three months ended June 30, 2005 compared to $0.2 million of stock-based compensation expense for the three months ended June 30, 2004. Stock-based compensation expense of $0.4 million was recognized in the three months ended June 30, 2005 related to the accelerated option vesting for two employees. Stock-based compensation expense included in general and administrative expense for the three months ended June 30, 2005 also included $385,000 of payroll taxes associated with CEI stock option exercises. CEI contributed capital for the same amount to reimburse us for these taxes.

Gain/ Loss on Sale of Property. In the second quarter of 2005, we sold a small gathering system for proceeds of $120,000 and recognize a gain of the same amount since this asset was fully depreciated.

Depreciation and Amortization. Depreciation and amortization expenses were $7.4 million for the three months ended June 30, 2005 compared to $5.9 million for the three months ended June 30, 2004, an increase of $1.5 million, or 24.5%. New treating plants placed in service resulted in an increase of $0.4 million. Amortization of contract costs increased $0.3 million due to the acquisition of some short-lived treating contracts from Cardinal in May 2005. The remaining $0.8 million increase in depreciation and amortization is a result of expansion projects, including our office expansion and other new assets.

Interest Expense. Interest expense was $3.2 million for the three months ended June 30, 2005 compared to $2.2 million for the three months ended June 30, 2004, an increase of $1.0 million, or 46.2%. The increase relates primarily to an increase in debt outstanding and higher interest rates between three-month periods (weighted average rate of 6.0% in 2005 compared to 5.4% in 2004).

Net Income. Net income for the three months ended June 30, 2005 was $4.5 million compared to $5.9 million for the three months ended June 30, 2004, a decrease of $1.4 million. This decrease was generally the result of the increase in gross margin of $5.7 million between comparative quarters from 2004 to 2005, partially offset by increases totaling $4.6 million in ongoing cash costs for operating expenses, general and administrative expenses and interest expense as discussed above. The increase in gross margin was further offset by increases in depreciation and amortization expense and stock-based compensation expense totaling $2.4 million.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $48.0 million for the six months ended June 30, 2005 compared to $37.9 million for the six months ended June 30, 2004, an increase of $10.1 million, or 27%. The largest portion of this increase was due to the acquisition of the LIG assets on April 1, 2004, which added $10.5 million to midstream gross margin. The acquisition of all outside interests in Crosstex Pipeline Partners, L.P. as of December 31, 2004, and the capital expansion of the Arkoma system during 2004 accounted for gross margin increases of $0.8 million and $0.6 million, respectively. An additional gross margin increase of $0.9 million was due to a measurement adjustment on the

Gregory Gathering system. These increases were partially offset by a $1.9 million increase in cost of gas due to a physical gas leak discussed above under “Three Months Ended June 30, 2005 Compared to Three Months Ended June 30, 2004”. An additional gross margin decrease of $1.0 million was due to price and volume fluctuations on other midstream systems.

Treating gross margin was $17.7 million for the six months ended June 30, 2005 compared to $11.8 million in the same period in 2004, an increase of $5.9 million, or 49.7%. The increase in treating plants in service from 62 plants at June 30, 2004 to 100 plants at June 30, 2005 contributed $3.8 million in gross margin. Existing plant assets contributed $1.1 million in gross margin growth due primarily to plant expansion projects and increased volumes. Also contributing to the increase was $0.7 million gross margin improvement from the Seminole plant due to an increase in volumes, fees and higher liquid prices.

The profit on energy trading activities was $0.4 million for the six months ended June 30, 2005 compared to $1.2 million for the six months ended June 30, 2004, a decrease of $0.8 million. Energy trading activity included approximately $0.7 million and $1.2 million of net profit related to our Commercial Services activities during the six months ended June 30, 2005 and 2004, respectively. Included in the six months ended June 30, 2005 is a $0.4 million loss associated with derivatives for third party on-system financial transactions and storage financial transactions that are considered energy trading activities. The Partnership recognized gains due to the ineffectiveness of certain cash flow hedges of $0.1 million during the six months ended June 30, 2005, which is also included in profit on energy trading activities.

Operating Expenses. Operating expenses were $23.7 million for the six months ended June 30, 2005 compared to $16.6 million for the six months ended June 30, 2004, an increase of $7.1 million, or 42.6%. An increase of $4.0 million was associated with the acquisition of the LIG assets. The growth in treating plants in service increased operating expenses by $2.2 million. Operating expenses included $0.2 million of stock-based compensation expense for the six months ended June 30, 2005 compared to $0.1 million of stock-based compensation expense for the six months ended June 30, 2004.

General and Administrative Expenses. General and administrative expenses were $14.2 million for the six months ended June 30, 2005 compared to $8.7 million for the six months ended June 30, 2004, an increase of $5.5 million, or 63.2%. The increase was primarily due to increases in staffing associated with the requirements of the LIG acquisition and growth in the Partnership’s treating business and its other assets as discussed above. Other variances include a charge of $0.7 million for unsuccessful transaction costs, $0.4 million for SOX 404 compliance, $0.2 million for audit fees and $0.2 million for bad debt reserve. General and administrative expenses included $1.3 million of stock-based compensation expense for the six months ended June 30, 2005 compared to $0.4 million for the six months ended June 30, 2004. Stock-based compensation expense during 2005 was higher than 2004 because $0.4 million of expense was recognized in the six months ended June 30, 2005 related to the accelerated option vesting for two employees. Stock-based compensation expense included in general and administrative expense for the six months ended June 30, 2005 also included $0.4 million of payroll taxes associated with CEI stock option exercises. CEI contributed capital for the same amount to reimburse us for these taxes.

Gain/ Loss on Sale of Property. In the first six months of 2005, we sold a treating plant and a small gathering system for proceeds totaling $0.3 million and recognized a gain of $0.2 million. In the first six months of 2004, we also sold two small gathering systems and recognized a net loss on sale of $0.3 million.

Depreciation and Amortization. Depreciation and amortization expenses were $14.3 million for the six months ended June 30, 2005 compared to $10.3 million for the six months ended June 30, 2004, an increase of $4.0 million, or 38.4%. The increase related to the LIG assets was $1.2 million. The new plants acquired from Graco in January 2005 and from Cardinal in May 2005, together with n treating plants placed in service resulted in an increase of $1.1 million. Amortization of contract costs increased $0.3 million due to the acquisition of some short-lived treating contracts from Cardinal in May 2005. The remaining $1.4 million increase in depreciation and amortization is a result of expansion projects, including our office expansion and other new assets.

Interest Expense. Interest expense was $6.6 million for the six months ended June 30, 2005 compared to $3.3 million for the six months ended June 30, 2004, an increase of $3.3 million. The increase relates primarily to an increase in debt outstanding and higher interest rates between six-month periods (weighted average rate of 6.2% in 2005 compared to 5.5% in 2004).

Net Income. Net income for the six months ended June 30, 2005 was $7.7 million compared to $11.6 million for the six months ended June 30, 2004, a decrease of $3.9 million. This decrease was generally the result of the increase in gross margin of $16.0 million, offset by increases totaling $14.8 million in ongoing cash costs for operating expenses, general and administrative expenses and interest expense as discussed above. The increase in gross margin was further offset by increases in depreciation and amortization expenses and stock-based compensation expense totaling $5.0 million.

Critical Accounting Policies

Information regarding the Partnership's Critical Accounting Policies is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2004.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $15.3 million for the six months ended June 30, 2005 compared to $24.9 million for the six months ended June 30, 2004. Income before non-cash income and expenses was $23.0 million in 2005 and $22.6 million in 2004. Changes in working capital used $7.7 million in cash flows from operating activities in 2005 as compared to $2.3 million in cash flows provided by working capital changes in 2004.

Net cash used in investing activities was $41.4 million and $88.3 million for the six months ended June 30, 2005 and 2004, respectively. Net cash used in investing activities during 2005 related to the $9.3 million Graco acquisition, the $6.7 million Cardinal acquisition and $12.8 million related to the refurbishment and installation of additional treating plants. The connection of new wells to various systems, pipeline integrity projects, pipeline relocations and various other internal growth projects totaled $13.0 million for the first half of 2005, including $3.1 million related to the new North Texas Pipeline project. Investing activity in 2004 included $73.0 million for the LIG acquisition.

Net cash provided by financing activities was $22.6 million for the six months ended June 30, 2005 compared to $63.9 million provided by financing activities for the six months ended June 30, 2004. Net proceeds from the issuance of approximately 1.5 million senior subordinated units in June 2005 provided cash of $51.1 million, including the general partner contribution. The proceeds were used to repay bank borrowings. Net bank borrowings of $55.1 million in the first half of 2005, before the June 2005 repayment from the proceeds from the issuance of senior subordinated units, were used to fund the acquisitions and the internal growth projects discussed above. Distributions to partners totaled $20.7 million in the first half of 2005, compared to distributions in the first half of 2004 of $15.8 million. Drafts payable decreased by $12.7 million requiring the use of cash in the six months ended June 30, 2005 as compared to an decrease in drafts payable of $16.5 million using cash from financing activities for the six months ended June 30, 2004. In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility.

Working Capital Deficit. We had a working capital deficit of $21.3 million as of June 30, 2005, primarily due to drafts payable of $26.0 million as of the same date. As discussed under "Cash Flows" above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank. We borrow money under our $250.0 million acquisition credit facility to fund checks as they are presented. As of June 30, 2005, we had $213.0 million of available borrowings under this facility.

June 2005 Sale of Senior Subordinated Units. In June 2005, we issued 1,495,410 senior subordinated units in a private equity offering for net proceeds of $51.1 million, including our general partners' $1.1 million capital contribution. The senior subordinated units were issued at $33.44 per unit, which represents a discount of 13.7% to the market value of common units on such date, and will automatically convert to common units on a one-for-one basis on February 24, 2006. The senior subordinated units will receive no distributions until their conversion to common units.

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 our cash flows; and
- Growth capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity, processing plants or treating plants, and to construct or acquire new pipelines, processing plants or treating plants, and expenditures made in support of that growth.

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

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.47 per quarter and to fund a portion of our anticipated capital expenditures through June 30, 2006. Total capital expenditures are budgeted to be approximately $124 million for the remainder of 2005, including $93 million for the North Texas Pipeline project. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of June 30, 2005.

Indebtedness

As of June 30, 2005 and December 31, 2004, long-term debt consisted of the following (in thousands):

	June 30, 2005	December 31, 2004
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at June 30, 2005 and December 31, 2004 were 5.34% and 4.99%, respectively	$ 37,000	$ 33,000
Senior secured notes, weighted average interest rate of 6.95%	115,000	115,000
Note payable to Florida Gas Transmission Company	650	700
	152,650	148,700
Less current portion	(1,815)	(50)
Debt classified as long-term	$ 150,835	$ 148,650

On March 31, 2005, we amended our bank credit facility, increasing availability under the facility to $250 million, eliminating the distinction between an acquisition and working capital facility and extending the maturity date from June 2006 to March 2010. Additionally, an accordion feature built into the credit facility allows us to increase the availability to $350 million.

Under the amended credit agreement, borrowings bear interest at our option at the administrative agent's reference rate plus 0% to 0.25% or LIBOR plus 1.00% to 1.75%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.00% to 1.75% per annum, plus a fronting fee of 0.125% per annum. We will incur quarterly commitment fees based on the unused amount of the credit facilities. The amendment to the credit facility also adjusted financial covenants requiring us to maintain:

- a maximum ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of 4.0 to 1.0, pro forma for any asset acquisitions (but during an acquisition adjustment period, as defined in the credit agreement, the maximum ratio is increased to 4.75 to 1.0); and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis, equal to 3.0 to 1.0.

In June 2005, we further amended its Shelf Agreement for its senior secured notes increasing its availability from $125 million to $200 million.

We were in compliance with all debt covenants at June 30, 2005 and expect to be in compliance for the next twelve months.

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

	Payments Due by Period						
	Total	2005	2006	2007	2008	2009	Thereafter
				(In millions)			
Long-Term Debt	$ 152.6	$ —	$ 6.5	$ 10.0	$ 9.4	$ 9.4	$ 117.3
Capital Lease Obligations	—	—	—	—	—	—	—
Operating Leases	7.8	0.9	1.5	1.4	1.3	1.2	1.5
Unconditional Purchase Obligations	29.8	29.8	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—	—
Total Contractual Obligations	$ 190.2	$ 30.7	$ 8.0	$ 11.4	$ 10.7	$ 10.6	$ 118.8

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

The unconditional purchase obligations for 2005 relate to the purchase of pipe for the construction of our North Texas Pipeline which is scheduled to commence in September 2005.

Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123 (Revised 2004), *Share-Based Payment* (SFAS No. 123R), which required that compensation related to all stock-based awards, including stock options, be recognized in the financial statements. This pronouncement replaces SFAS No. 123, *Accounting for Stock-Based Compensation,* and supersedes APB Option No. 25, *Accounting for Stock Issued to Employees* and will be effective beginning July 1, 2005. We have previously recorded stock compensation pursuant to the intrinsic value method under APB No. 25, whereby no compensation was recognized for most stock option awards. We expect that stock option grants will continue to be a significant part of employee compensation, and therefore, SFAS No. 123R will impact our financial statements. We reviewed the impact of SFAS No. 123R and we believe that the pro forma effect of recording compensation for all stock awards at fair value utilizing the Black-Scholes method for the three and six months ended June 30, 2005 and 2004 presented in Note 1(b) to our financial statements is not materially different.

In March 2005, the FASB issued Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations"* (FIN 47). FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, *"Accounting for Asset Retirement Obligations"*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FIN 47 provides that a liability for the fair value of a conditional asset retirement obligation should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB Statement No. 143. FIN 47 is effective for fiscal years ending after December 15, 2005, and is not expected to affect our financial position or results of operations.

Disclosure Regarding Forward-Looking Statements

This report on Form 10-Q includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto and including, without limitation, the information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations"), are forward-looking statements. These statements can be identified by the use of forward-looking terminology such as "forecast," "may," "believe," "will," "expect," "anticipate," "estimate," "continue" or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. In addition to specific uncertainties discussed elsewhere in this Form 10-Q, the following risks and uncertainties may affect our performance and results of operations:

- we may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to pay the minimum quarterly distribution each quarter;
- if we are unable to contract for new natural gas supplies, we will be unable to maintain or increase the throughput levels in our natural gas gathering systems and asset utilization rates at our treating and processing plants to offset the natural decline in reserves;
- our profitability is dependent upon the prices and market demand for natural gas and NGLs, which are beyond our control and have been volatile;
- our future success will depend in part on our ability to make acquisitions of assets and businesses at attractive prices and to integrate and operate the acquired business profitably;
- Crosstex Energy, Inc. owns approximately 49.9% aggregate limited partner interest of us and it owns and controls our general partner, thereby effectively controlling all limited partnership decisions; conflicts of interest may arise in the future between Crosstex Energy, Inc. and its affiliates, including our general partner, and our partnership or any of our unitholders;
- since we are not the operator of certain of our assets, the success of the activities conducted at such assets are outside our control;
- we operate in very competitive markets and encounter significant competition for natural gas supplies and markets;
- we are subject to risk of loss resulting from nonpayment or nonperformance by our customers or counterparties;
- we may not be able to retain existing customers, especially key customers, or acquire new customers at rates sufficient to maintain our current revenues and cash flows;
- the construction of gathering, processing and treating facilities requires the expenditure of significant amounts of capital and subjects us to construction risks and risks that natural gas supplies will not be available upon completion of the facilities;
- our business involves many hazards and operational risks, some of which may not be fully covered by insurance. Our operations are subject to 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 from 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. We are not fully insured against all risks incident to our business. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition;

- we are subject to extensive and changing federal, state and local laws and regulations designed to protect the environment, and these laws and regulations could impose liability for remediation costs and civil or criminal penalties for non-compliance;
- our common units may not have significant trading volume or liquidity, and the price of our common units may be volatile and may decline if interest rates increase; and
- cash distributions paid by us may not necessarily represent earnings.

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

Item 3. *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 natural gas liquid ("NGL") products we produce versus the value of the gas used in fuel and shrinkage in their production. In addition, a portion of our loss at certain processing operations is denominated in natural gas liquids. We also incur credit risks and risks related to interest rate variations.

Commodity Price Risk. Approximately 11% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our resale margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. We have hedged approximately 76% of our exposure to gas price fluctuations through the end of 2005 and 79% of our exposure to gas price fluctuations for the first six months of 2006. We have also hedged approximately 80% of our exposure to liquids price fluctuations through the end of 2005.

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

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

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

2. Percent of proceeds contracts: Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from

processing cannot become negative under percent of proceeds contracts, but decline during periods of low NGL prices.

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

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

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

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

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

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

Concentration Risk. The counterparty to substantially all of the Partnership's derivative contracts as of June 30, 2005 is BP Corporation. Although we do not believe we have a counterparty risk with BP Corporation, our loss would be substantial if BP Corporation were to default.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our long-term debt with floating interest rates. At June 30, 2005, we had $37.0 million of indebtedness outstanding under floating rate debt. The impact of a 1% increase in interest rates on our expected debt would result in an increase in interest expense and a decrease in income before taxes of approximately $0.4 million per year. This amount has been determined by considering the impact of such hypothetical interest rate increase on our non-hedged, floating rate debt outstanding at June 30, 2005.

Operational Risk. As with all mid-stream energy companies and other industrials, we have operational risk associated with operating our plant and pipeline assets that can have a financial impact, either favorable or unfavorable, and as such risk must be effectively managed. We view our operational risk in the following categories.

General Mechanical Risk. Both our plants and pipelines expose us to the possibilities of a mechanical failure or process upset that can result in loss of revenues and replacement cost of either volume losses or damaged equipment. These mechanical failures manifest themselves in the form of equipment failure/malfunction as well as operator error. We are proactive in managing this risk on two fronts. First we effectively hire and train our operational staff to operate the equipment in a safe manner, consistent with defined processes and procedures, and second, we perform preventative and routine maintenance on all of our mechanical assets.

Measurement Risk. In complex midstream systems such as ours, it is normal for there to be differences between gas measured into our systems and those measured out of the system which is referred to as system balance. These system balances are normally due to changes in line pack, gas vented for routine operational and non-routine reasons, as well as due to the inherent inaccuracies in the physical measurement of gas. We employ the latest gas measurement technology when appropriate, in the form of EFM (Electronic Flow Measurement) computers. Nearly all of our new supply and market connections are equipped with EFM. Retro-fitting older measurement technology is done on a case-by-case basis. Electronic digital data from these devices can be transmitted to a central control room via radio, telephone, cell phone, satellite or other means. With EFM computers, such a communication system is capable of monitoring gas flows and pressures in real-time and is commonly referred to as SCADA (Supervisory Control And Data Acquisition). We expect to continue to increase our reliance on electronic flow measurement and SCADA, which will further increase our awareness of measurement discrepancies as well as reduce our response time should a pipeline failure occur.

Item 4. *Controls and Procedures*

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on the evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2005 in alerting them in a timely manner to material information required to be disclosed in our periodic reports filed with the Securities and Exchange Commission.

There has been no change in our internal controls over financial reporting that occurred during the three months ended June 30, 2005 that has materially affected, or is reasonable likely to materially affect, our internal controls over financial reporting. We implemented an enterprise-wide accounting system on January 1, 2005. We expect this new system to improve our control environment as its full capabilities are deployed throughout our operations during 2005.

PART II — OTHER INFORMATION

Item 6. *Exhibits*

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Third Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of June 24, 2005 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed on June 24, 2005).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).

Number		Description
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-106927).
4.1	—	Registration Rights Agreement, by and among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Tortoise Energy Capital Corporation and Tortoise Energy Infrastructure Corporation (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on June 24, 2005).
10.1	—	Third Amended and Restated Credit Agreement, dated as of March 31, 2005 among Crosstex Energy, L.P., Crosstex Energy Services, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 31, 2005, filed with the Commission on April 6, 2005).
10.2	—	Amended and Restated $125,000,000 Senior Secured Notes Master Shelf Agreement, dated as of March 31, 2005 among Crosstex Energy, L.P., Crosstex Energy Services, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 31, 2005, filed with the Commission on April 6, 2005).
10.3	—	Senior Subordinated Unit Purchase Agreement, by and among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Tortoise Energy Capital Corporation and Tortoise Energy Infrastructure Corporation (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on June 24, 2005).
31.1*	—	Certification of the principal executive officer.
31.2*	—	Certification of the principal financial officer.
32.1*	—	Certification of the principal executive officer and principal financial officer of the Company pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 5th day of August, 2005.

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ William W. Davis

William W. Davis
Executive Vice President and
Chief Financial Officer

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* Filed herewith.

Exhibit 31.1

CERTIFICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

/s/ Barry E. Davis

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

Date: August 5, 2005

Exhibit 31.2

CERTIFICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

/s/ William W. Davis

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

Date: August 5, 2005

Exhibit 32.1

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

In connection with the Quarterly Report of Crosstex Energy, L.P. (the "Registrant") on Form 10-Q for the quarter ended June 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

/s/ Barry E. Davis

Barry E. Davis
Chief Executive Officer

August 5, 2005

/s/ William W. Davis

William W. Davis
Chief Financial Officer

August 5, 2005

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