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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 September 30, 2004

OR

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

For the transition period from to

Commission file number: 000-50067

Crosstex Energy, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**16-1616605**
(State of organization)	*(I.R.S. Employer Identification No.)*

2501 CEDAR SPRINGS, SUITE 600

DALLAS, TEXAS 75201
(Address of principal executive offices)
(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 October 29, 2004, the Registrant had 8,750,659 common units and 9,334,000 subordinated units outstanding.

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GLOSSARY OF TERMS

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

/d = per day
MMBtu = million British thermal units
NGL's = Natural gas liquids

CROSSTEX ENERGY, L.P.

CONSOLIDATED BALANCE SHEETS

	September 30, 2004	December 31, 2003
	(Unaudited)	(Restated)
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 715	$ 166
Accounts receivable:		
Trade	33,575	10,238
Accrued revenues	152,363	124,517
Imbalances	627	447
Related party	319	1,618
Note receivable	575	535
Other	834	2,588
Fair value of derivative assets	10,211	4,080
Prepaid expenses and other	3,027	1,979
Total current assets	202,246	146,168
Property and equipment:		
Property and equipment	350,361	228,386
Accumulated depreciation	(39,199)	(24,477)
Property and equipment, net	311,162	203,909
Intangible assets, net	5,610	5,366
Goodwill, net	4,873	4,873
Investment in limited partnerships	453	2,560
Other assets, net	3,914	3,174
Total assets	$ 528,258	$ 366,050
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 24,861	$ 10,446
Accounts payable	4,772	6,325
Accrued gas purchases	153,176	119,900
Accounts payable — related party	—	448
Accrued imbalances payable	1,520	212
Fair value of derivative liabilities	10,976	2,486
Current portion of long-term debt	50	50
Other current liabilities	18,122	10,873
Total current liabilities	213,477	150,740
Long-term debt	153,650	60,700
Deferred tax liability	13,055	—
Minority interest in subsidiary	2,670	—
Fair value of derivative liabilities	235	—
Partners' equity:		
Common unit-holders (8,750,659 and 8,716,000 units issued and outstanding at September 30, 2004 and December 31, 2003, respectively)	113,537	116,780
Subordinated unit-holders (9,334,000 units issued and outstanding at September 30, 2004 and December 31, 2003)	29,770	33,593
General partner interest (2% interest with 369,075 and 368,368 equivalent units outstanding at September 30, 2004 and December 31, 2003, respectively)	3,744	2,854
Accumulated other comprehensive income (loss)	(1,880)	1,383
Total partners' equity	145,171	154,610
Total liabilities and partners' equity	$ 528,258	$ 366,050

See accompanying notes to consolidated financial statements.

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CROSSTEX ENERGY, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(Unaudited) (In thousands, except per unit amounts)			
Revenues:				
Midstream	$501,004	$276,222	$1,327,181	$745,567
Treating	7,880	6,976	22,592	17,453
Total revenues	508,884	283,198	1,349,773	763,020
Operating costs and expenses:				
Midstream purchased gas	478,536	264,035	1,266,624	715,514
Treating purchased gas	1,229	1,860	4,092	6,311
Operating expenses	10,013	5,462	26,542	12,007
General and administrative	4,907	1,721	13,236	5,112
Stock based compensation	288	1,577	766	4,649
Profit on energy trading activities	(766)	(646)	(1,792)	(1,491)
Gain on sale of property	(287)	—	(12)	—
Depreciation and amortization	6,160	4,031	16,499	9,077
Total operating costs and expenses	500,080	278,040	1,325,955	751,179
Operating income	8,804	5,158	23,818	11,841
Other income (expense):				
Interest expense, net	(2,872)	(1,321)	(6,214)	(2,196)
Other	51	51	254	50
Total other income (expense)	(2,821)	(1,270)	(5,960)	(2,146)
Income before minority interest and income tax	5,983	3,888	17,858	9,695
Minority interest in subsidiary	(51)	—	(150)	—
Income tax expense	13	—	(116)	—
Net income	$ 5,945	$ 3,888	$ 17,592	$ 9,695
General partner interest in net income	$ 1,563	$ 450	$ 4,005	$ 621
Limited partners' interest in net income	$ 4,382	$ 3,438	$ 13,587	$ 9,074
Net income per limited partners' unit:				
Basic	$ 0.24	$ 0.22	$ 0.75	$ 0.61
Diluted	$ 0.23	$ 0.22	$ 0.73	$ 0.60
Weighted average limited partners' units outstanding:				
Basic	18,083	15,462	18,079	14,890
Diluted	18,662	15,860	18,607	15,096

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY

Nine Months Ended September 30, 2004

	Common Units	Subordinated Units	General Partner Interest	Accumulated Other Comprehensive Income	Total
			(Unaudited) (In thousands)		
Balance, December 31, 2003 (Restated)	$116,780	$ 33,593	$ 2,854	$ 1,383	$154,610
Stock based compensation	296	315	155	—	766
Distributions	(10,453)	(11,154)	(3,270)	—	(24,877)
Net income	6,571	7,016	4,005	—	17,592
Proceeds from exercise of unit options	343	—	—	—	343
Hedging gains or losses reclassified to earnings	—	—	—	(4,564)	(4,564)
Adjustment in fair value of derivatives	—	—	—	1,301	1,301
Balance, September 30, 2004	$113,537	$ 29,770	$ 3,744	$ (1,880)	$145,171

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(Unaudited) (In thousands)	
Net income	$17,592	$ 9,695
Hedging gains or losses reclassified to earnings	(4,564)	2,056
Adjustment in fair value of derivatives	1,301	(4,258)
Comprehensive income	$14,329	$ 7,493

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income	$ 17,592	$ 9,695
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	16,499	9,077
Income from investment in affiliated partnerships	(229)	(173)
Non-cash stock based compensation	766	4,649
Gain on sale of property	(12)	—
Minority interest in subsidiary	150	—
Deferred taxes	(168)	—
Changes in current assets and liabilities, net of acquisition effects:		
Accounts receivable and accrued revenue	(2,942)	(24,943)
Prepaid expenses	(633)	(773)
Accounts payable, accrued gas purchases, and other accrued liabilities	(12,114)	24,396
Fair value of derivatives	(671)	(382)
Other	684	781
Net cash provided by operating activities	18,922	22,327
Cash flows from investing activities:		
Additions to property and equipment	(27,018)	(27,135)
Asset purchases and acquisitions	(73,474)	(68,124)
Proceeds from sale of property	611	—
Additions to other non-current assets	(344)	(1,818)
Investments in affiliated partnerships	134	(1,563)
Net cash used in investing activities	(100,091)	(98,640)
Cash flows from financing activities:		
Proceeds from borrowings	381,000	238,600
Payments on borrowings	(288,050)	(217,900)
Debt issuance costs	(1,113)	(1,340)
Increase (decrease) in drafts payable	14,415	5,821
Distribution to partners	(24,877)	(8,445)
Proceeds from exercise of unit options	343	—
Proceeds from issuance of common units, net of offering costs	—	57,159
Contributions from partners	—	1,266
Net cash provided by financing activities	81,718	75,161
Net increase in cash and cash equivalents	549	(1,152)
Cash and cash equivalents, beginning of period	166	1,308
Cash and cash equivalents, end of period	$ 715	$ 156
Cash paid for interest	$ 4,896	$ 1,998
Income taxes paid	$ 285	$ —

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2004
(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 include the assets, liabilities, and results of operations of the Partnership (or CES as its predecessor) and its wholly owned subsidiaries. The consolidated operations are hereafter referred to herein collectively as the "Partnership." All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for the prior years to conform to the current presentation.

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/ A for the year ended December 31, 2003.

(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) Income Taxes

The new entities the Partnership formed to acquire LIG Pipeline Company and its subsidiaries, as discussed more fully in Note 3, are treated as taxable corporations for income tax purposes.

For the nine months ended September 30, 2004, the Partnership recognized a current tax expense of $284,000 on the LIG entities net taxable income and a deferred tax benefit of $168,000. A deferred tax liability of $13,224,000 was recorded at the acquisition date. The deferred tax represents future taxes payable on the difference between the tax fair market value and tax basis of the net assets acquired based on our preliminary purchase price allocation.

(c) 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 exercise price of the options at period end.

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 September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Net income, as reported	$5,945	$ 3,888	$17,592	$ 9,695
Add: Stock-based employee compensation expense included in reported net income	288	1,577	766	4,649
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(300)	(1,655)	(893)	(4,918)
Pro forma net income	$5,933	$ 3,810	$17,465	$ 9,426
Net income per limited partner unit, as reported:				
Basic	$ 0.24	$ 0.22	$ 0.75	$ 0.61
Diluted	$ 0.23	$ 0.22	$ 0.73	$ 0.60
Pro forma net income per limited partner unit:				
Basic	$ 0.24	$ 0.22	$ 0.74	$ 0.59
Diluted	$ 0.23	$ 0.21	$ 0.72	$ 0.58

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 nine months ended September 30, 2004:

	2004
Options Granted	455,694
Weighted average dividend yield	6.4%
Weighted average expected volatility	24%
Weighted average risk free interest rate	3.24%
Weighted average expected life	5
Contractual life	10
Weighted average of fair value of unit options granted	$ 3.12

No Crosstex Energy, Inc. (CEI) options were granted to officers or employees in 2004. Stock based compensation associated with the CEI option 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.

CEI modified certain outstanding options attributable to its shares of common stock in the first quarter of 2003, which allowed the option holders to elect to be paid in cash for the modified options based on the fair value of the options. The total number of CEI options which were modified was approximately 364,000. These modified options have been accounted for using variable accounting as of the option modification date. The Partnership accounted for the modified options as variable options until the holders elected to cash out the options or the election to cash out the options lapsed. CEI was responsible for paying the intrinsic value of the options for the holders who elected to cash out their options. December 31, 2003 was the last valuation date that a holder of modified options could elect the cash-out alternative. Accordingly, effective January 1, 2004, the remaining modified options are accounted for as fixed options. Beginning in the first quarter of 2003, the Partnership recognized stock compensation expense based on the estimated fair value of the modified options at period end. The Partnership recognized stock-based compensation expense of approximately $1.6 million and $4.6 million related to the variable options for the three and nine months ended September 30, 2003, respectively.

In February 2004, 75,000 restricted shares in CEI were issued to senior management under its long-term incentive plan with an intrinsic value of $2,183,000. The CEI restricted shares vest over a three-year period and the intrinsic value is amortized into stock-based compensation expense over the vesting period. In February 2004, 1,406 Partnership restricted units with an intrinsic value of $29,000 were issued to a director, at his election, for his 2004 annual director fee. These restricted units were vested upon issuance and the intrinsic value of the units was charged to stock-based compensation expense.

(d) 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 nine months ended September 30, 2004 and 2003. The computation of diluted earnings per unit further assumes the dilutive effect of unit options and the restricted units.

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

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2004 and 2003 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Basic earnings per unit:				
Weighted average limited partner units outstanding	18,083	15,462	18,079	14,890
Diluted earnings per unit:				
Weighted average limited partner units outstanding	18,083	15,462	18,079	14,890
Dilutive effect of restricted units	98	—	98	—
Dilutive effect of exercise of options outstanding	481	398	430	206
Diluted units	18,662	15,860	18,607	15,096

All outstanding units were included in the computation of diluted earnings per unit.

(e) New Accounting Pronouncement

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

(2) Restatement of Previously Issued Financial Statements

In July 2004, we determined that clerical errors had occurred in 2002 accounting that resulted in certain reconciling items not being properly cleared from accounts payable, accounts receivable and accrued gas purchases with an offsetting decrease in income of $1.7 million in 2002. As a result of correcting these errors, we have restated our consolidated balance sheet and consolidated statements of changes in partners' equity for the year ended December 31, 2003 which are included in our Form 10-K/ A filed on August 10, 2004.

(3) Significant Asset Purchases and Acquisitions

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 $73.5 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.

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

Cash paid to AEP	$ 70,509
Lease obligations bought out	451
Transaction costs	2,514
Total Purchase Price	$ 73,474
Assets acquired:	
Current assets	$ 45,602
Property plant & equipment	91,953
Intangibles	1,000
Liabilities assumed:	
Current liabilities	(51,857)
Deferred tax liability	(13,224)
Total Purchase Price	$ 73,474

The purchase price allocation for the LIG acquisition has not been finalized because the Partnership's valuation consultant has not issued its report related to the purchase price allocation.

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

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

	Pro Forma		
	Three Months Ended September 30,	Nine Months Ended September 30,	
	2003	2004	2003
	(Unaudited)		
Revenue	$ 483,709	$1,551,053	$1,470,874
Net income	$ 1,526	$ 16,410	$ 3,595
Net income per limited partner unit	$ 0.07	$ 0.69	$ 0.21

(4) Investment in Limited Partnerships and Note Receivable

The Partnership owns a 7.86% weighted average interest as the general partner in the five gathering systems of Crosstex Pipeline Partners, L.P. (CPP), a 20.31% interest as a limited partner in CPP, 50% interest in the J.O.B. J.V. and a 50% interest in CDC. In January 2004, the Partnership began consolidating its investment in CDC pursuant to FIN No. 46R. The Partnership accounts for its investments in J.O.B. J.V. and CPP under the equity method, as it exercises significant influence in operating decisions as a general partner in CPP and as a 50% owner in the joint venture. Under this method, the Partnership carries its investments at cost and records its equity in net earnings of the affiliated partnerships as income in other income (expense) in the consolidated statement of operations, and distributions received from them are recorded as a reduction in the Partnership's investment in the affiliated partnership.

In connection with the formation of CDC, the Partnership agreed to loan the CDC partner up to $1.5 million for its initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to the Partnership attributable to CDC partner's 50% share of distributable cash flow to repay the loan. Any balance remaining on the note is due in August 2007. The current portion of loan receivable of $575,000 from the CDC partner is included in current notes receivable as of September 30, 2004. The remaining balance of $1,060,000 is included in other non-current assets as of September 30, 2004.

(5) Long-Term Debt

As of September 30, 2004 and December 31, 2003, long-term debt consisted of the following (dollars in thousands):

	September 30, 2004	December 31, 2003
Acquisition credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at September 30, 2004 and December 31, 2003 were 4.43% and 2.92%, respectively	$ 38,000	$ 20,000
Senior secured notes, weighted average interest rate of 6.95% and 6.93%, respectively	115,000	40,000
Note payable to Florida Gas Transmission Company	700	750
	153,700	60,750
Less current portion	(50)	(50)
Debt classified as long-term	$ 153,650	$ 60,700

In conjunction with the April 2004 acquisition of the LIG Pipeline Company and its subsidiaries discussed in Note (3), the Partnership amended its bank credit facility to increase the borrowing base under its senior secured revolving acquisition facility from $70 million to $100 million and to increase the borrowing base under its senior secured revolving credit working capital and letter of credit facility from $50 million to $100 million. Additionally, the current ratio covenant was eliminated under this amendment. In June 2004, the bank credit facility was further amended allowing for an increase in senior secured notes to $125 million and eliminating the minimum tangible net worth covenant.

In June 2004, the Partnership completed a private placement offering of $75 million in senior secured notes with Prudential Capital Group. The notes mature in 10 years, with an average life of eight years, have an annual coupon of 6.96% and are callable after three years at 103.5% of par. The notes were used to repay borrowings under the Partnership's revolving credit facility.

As part of the $75 million private placement, the Master Shelf Agreement (the "Agreement") governing the notes was amended, the following being the significant amendments:

- increased the aggregate amount of notes that may be issued under the Agreement to $125 million;
- extended the issuance period from June 2006 to June 2007;
- established a release of collateral provision should the Partnership obtain a senior unsecured debt rating of investment grade by certain rating agencies; and
- provided a call premium on the $75 million placement beginning June 2007 through June 2013 at rates declining from 3.50% to 0%. The notes are not callable prior to June 2007.

In October 2002, the Partnership entered into an interest rate swap covering a principal amount of $20 million for a period of two years. The Partnership is subject to interest rate risk on its acquisition credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 2.29%, on $20 million of related debt outstanding over the term of the swap agreement which expires on November 1, 2004. The Partnership has accounted for this swap as a cash flow hedge of the variable interest payments related to the $20 million of the acquisition credit facility outstanding. Accordingly, unrealized gains or losses relating to the swap which are recorded in other comprehensive income will be reclassified from other comprehensive income to interest expense over the period hedged. The fair value of the interest rate swap at September 30, 2004 was a $32,000 liability and is included in fair value of derivative liabilities.

(6) Partners' Capital

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 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 $1,474,000 and $3,728,000 were earned by our general partner for the three months and nine months ended September 30, 2004. 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 third quarter 2004 distribution of $0.43 per unit to be paid on November 18, 2004.

(7) Derivatives

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

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

	September 30, 2004	December 31, 2003
Fair value of derivative assets — current	$ 10,211	$ 4,080
Fair value of derivative assets — long term	—	—
Fair value of derivative liabilities — current	(10,945)	(2,278)
Fair value of derivative liabilities — long term	(235)	—
Net fair value of derivatives	$ (1,000)	$ 1,802

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes (not held for trading purposes) at September 30, 2004 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than December 2005, with no single contract longer than six months. The Partnership's counterparties to hedging contracts include UBS Financial, Morgan Stanley Capital Group, BP Corporation, Duke Energy Trading and Marketing, and AEP Energy Services. Changes in the fair value of the Partnership's derivatives related to Producer Services gas marketing activities are recorded in earnings. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings.

September 30, 2004				
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
				(In thousands)
Cash Flow Hedge:				
Natural gas swaps cash flow hedge	1,649,356	Fixed prices ranging from $4.85 to $7.07 settling against	October 2004 — December 2005	$ 466
Natural gas swaps cash flow hedge	(2,335,000)	various Inside FERC Index prices	October 2004 — December 2005	$ (1,791)
Total natural gas swaps cash flow hedge				$ (1,325)
Natural gas liquids (“NGLS”) swaps cash flow hedge	(2,917,404)	Fixed prices ranging from $0.5113 to $0.9975 settling against Mt. Belvieu Average of daily postings (non-TET)	October 2004 — December 2004	$ (524)
Total NGL swaps cash flow hedge				$ (524)
Swing swaps mark to market hedges(a)	3,185,000	Fixed prices ranging from $5.795 to $5.99 settling against	October 2004	$ (56)
Physical offset to Swing swaps mark to market hedges	(3,185,000)	various Inside FERC Index prices	October 2004	$ 93
Total Swing swap cash flow hedge				$ 37
Mark to Market derivatives:				
Third party on-system financial swaps	3,994,000	Fixed prices ranging from $4.83 to $6.70 settling against	October 2004 — June 2005	$ 3,891
Third party on-system financial swaps	(681,000)	various Inside FERC Index prices	October 2004 — June 2005	$ (635)
Total third party on-system financial swaps				$ 3,256
Physical offset to third party on-system transactions	681,000	Fixed prices ranging from $4.675 to $6.93 settling against	October 2004 — June 2005	$ 661
Physical offset to third party on-system transactions	(3,994,000)	various Inside FERC Index prices	October 2004 — June 2005	$ (3,607)
Total physical offset to marketing trading transactions swaps				$ (2,946)

September 30, 2004				
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
				(In thousands)
Marketing trading financial swaps	310,000	Fixed prices ranging from $4.50 to $5.945 settling against	October 2004 — March 2005	$ 355
Marketing trading financial swaps	(450,000)	various Inside FERC Index prices	October 2004 — March 2005	$ (796)
Total marketing trading financial swaps				$ (441)
Physical offset to marketing trading transactions	450,000	Fixed prices ranging from $4.52 to $5.885 settling against	October 2004 — March 2005	$ 822
Physical offset to marketing trading transactions	(310,000)	various Inside FERC Index prices	October 2004 — March 2005	$ (350)
Total physical offset to marketing trading transactions swaps				$ 472
Fair Value hedges:				
Financial fair value hedges	(300,000)	Fixed prices ranging from $4.83 to $6.70 settling against various Inside FERC Index prices	February 2005	$ (344)
Total financial fair value hedges				$ (344)
Physical offset to fair value hedges	300,000	Fixed prices ranging from $4.675 to $6.93 settling against	September 2004	$ (1,522)
Physical offset to fair value hedges	(300,000)	various Inside FERC Index prices	February 2005	$ 2,368
Total physical offset to marketing trading transactions swaps				$ 846

(a) Swing swaps are used to hedge the price exposure we have when we buy or sell a volume of gas at a first of the month index price and the other side of the transaction is priced at a daily gas price during the month or vice versa. The swing swap functions to hedge against this exposure by buying or selling a swap to balance the quantity of gas we are buying and selling on a daily and fixed price basis.

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

Assets and liabilities related to Producer Services that are accounted for as derivative contracts held for trading purposes are included in the fair value of derivative assets and liabilities and Producer Services operating results are recorded net as profit (loss) on energy trading activities 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
September 30, 2004	$ 30	—	—	$ 30
December 31, 2003	$ (26)	—	—	$ (26)

(8) Transactions with Related Parties

General and Administrative Expense Cap

The Partnership had a $6.0 million annual ($1.5 million quarterly) general and administrative cap for the twelve-month period ended in December 2003, per its partnership agreement. CEI bore the cost of any excess general and administrative expenses. During the three and nine months ended September 30, 2003, the Partnership had excess expenses of approximately $0.9 and $2.1 million, respectively. The general partner is also reimbursed for direct charges it incurs on behalf of partnership business development activities. Such charges totaled $0.6 million for the nine months ended September 30, 2003 and are included in general and administrative expenses.

Camden Resources, Inc.

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden). Camden is an affiliate of the Partnership by way of equity investments made 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 September 30, 2004 and 2003, the Partnership purchased natural gas from Camden in the amount of approximately $10.3 million and $1.5 million, respectively, and received approximately $565,000 and $470,000 in treating fees from Camden. The Partnership purchased natural gas from Camden in the amount of approximately $28.5 million and $7.0 million for the nine months ended September 30, 2004 and 2003, respectively, and received approximately $1.8 million and $1.0 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 September 30, 2004 and 2003, the Partnership bought natural gas from CPP in the amount of approximately $2.9 million and $2.3 million and paid for transportation of approximately $13,500 and $7,000, respectively, to CPP. During the nine months ended September 30, 2004 and 2003, the Partnership bought natural gas from CPP in the amount of approximately $8.4 million and $6.2 million and paid for transportation of approximately $35,000 and $31,000, respectively, to CPP.

- During the three months ended September 30, 2004 and 2003, the Partnership received a management fee from CPP of $31,000 in each period. During the nine months ended September 30, 2004 and 2003, the Partnership received a management fee from CPP of $94,000 in each period.

- During the three months ended September 30, 2004 and 2003, the Partnership received distributions from CPP in the amount of approximately $41,000 and $26,000, respectively. During the nine months ended September 30, 2004 and 2003, the Partnership received distributions from CPP in the amount of approximately $91,000 and $84,000, respectively.

(9) 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 two assets from DEFS in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas and a compressor station near Cadeville, Louisiana. At both of these sites, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/ or remediation are underway to address those impacts. The remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million, and the remediation cost for the Cadeville site is currently estimated to be approximately $1.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of both the Conroe and Cadeville sites. Moreover, DEFS has entered into an agreement with a third-party company pursuant to which the remediation costs associated with the Conroe site have been assumed by this third-party company that specializes in remediation work. Therefore, the Partnership does not expect to incur any material environmental liability associated with the Conroe or Cadeville sites.

The Partnership acquired LIG Pipeline Company, and its subsidiaries on April 1, 2004. Contamination from historical operations has been identified at a number of sites within the acquired properties. The Partnership has been indemnified by the seller for these identified sites, and does not expect to incur any material environmental liability associated with these sites. Additionally, possible issues have been discovered with respect to Clean Air Act monitoring deficiencies. The Partnership has disclosed these deficiencies to Louisiana Department of Environmental Quality and is working with the department to correct permit conditions and address modifications to facilities to bring them into compliance. The Partnership does not expect to incur any material environmental liability associated with these issues.

(c) Other

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

The Partnership receives notices from pipeline companies from time to time of gas volume allocation corrections related to gas deliveries on their pipeline systems. These allocation corrections normally have little impact on the Partnership's gross margin because the Partnership balances its purchases and sales in the pipelines and both the purchase and sale on the pipeline system require corrections. As of December 31, 2003, a subsidiary of the Partnership was involved in a dispute related to one such allocation correction with a pipeline company and a customer on that pipeline. As of December 31, 2003, the Partnership had recorded a receivable of $1.2 million in other current receivables and a liability of $1.2 million in other current liabilities related to this allocation correction. The Partnership resolved this dispute during the second quarter of 2004 at no loss to the Partnership.

In May, 2003, four landowner groups filed suit against the Partnership in the 267th Judicial District Court in Victoria County, Texas seeking damages related to the expiration of an easement for a segment of one of its pipelines located in Victoria County, Texas. In 1963, the original owners of the land granted an easement for a term of 35 years, and the prior owner of the pipeline failed to renew the easement. The Partnership filed a condemnation counterclaim in the District Count suit and it filed, in a separate action in the County Court, a condemnation suit seeking to condemn a 1.38 mile long easement across the land. Pursuant to condemnation procedures under the Texas Property Code, three special commissioners were appointed to hold a hearing to determine the amount of the landowner's damages. In August 2004 a hearing was held and the special commissioners awarded damages to the current landowners in the amount of $877,500. The Partnership has timely objected to the award of the special commissioners and the condemnation case will now be tried in the County Court. The damages award by the special commissioners will have no effect and cannot be introduced as evidence in the trial. The trial 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 trial 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. If damages related to this matter are less than such posted amount, the excess posted funds will be returned to the Partnership. The Partnership is not able to predict the ultimate outcome of this matter.

(10) 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 Producer Services operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or though fixed monthly payments. Included in the Treating division are four gathering systems that are connected to the treating plants and the non-operated 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 assets. Inter-segment sales are at cost.

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 September 30, 2004:			
Sales to external customers	$501,004	$ 7,880	$508,884
Inter-segment sales	1,655	(1,655)	—
Interest expense, net	2,827	45	2,872
Stock-based compensation expense	238	50	288
Depreciation and amortization	2,483	3,677	6,160
Segment profit	4,634	1,311	5,945
Segment assets	447,789	80,469	528,258
Capital expenditures	6,064	5,670	11,734

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Midstream	Treating	Totals
		(In thousands)	
Three months ended September 30, 2003:			
Sales to external customers	$ 276,222	$ 6,976	$ 283,198
Inter-segment sales	1,583	(1,583)	—
Interest expense, net	1,288	33	1,321
Stock-based compensation expense	1,262	315	1,577
Depreciation and amortization	2,811	1,220	4,031
Segment profit	2,368	1,520	3,888
Segment assets	282,387	66,214	348,601
Capital expenditures	8,433	2,259	10,692
Nine months ended September 30, 2004:			
Sales to external customers	$1,327,181	$22,592	$1,349,773
Inter-segment sales	4,493	(4,493)	—
Interest expense, net	6,110	104	6,214
Stock-based compensation expense	633	133	766
Depreciation and amortization	10,747	5,752	16,499
Segment profit	11,983	5,609	17,592
Segment assets	447,789	80,469	528,258
Capital expenditures	12,317	14,701	27,018
Nine months ended September 30, 2003:			
Sales to external customers	$ 745,567	$17,453	$ 763,020
Inter-segment sales	5,492	(5,492)	—
Interest expense, net	2,144	52	2,196
Stock-based compensation expense	3,719	930	4,649
Depreciation and amortization	6,526	2,551	9,077
Segment profit	6,798	2,897	9,695
Segment assets	282,387	66,214	348,601
Capital expenditures	20,512	6,623	27,135

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. on July 12, 2002 to acquire indirectly substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast 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 nine months ended September 30, 2004, 77% of our gross margin was generated in the Midstream division, with the balance in the Treating division. We focus on gross margin to manage our business because our business is generally to gather, process, transport, market or treat gas for a fee or a buy-sell margin.

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:

- gathering, transporting and reselling 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 "Item 3. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk" below for a discussion of how we manage our business to reduce the impact of price volatility.

We generate producer services revenues through the purchase and resale of natural gas. 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 55% (including the Seminole Plant, which contributed 32% of the operating income) of the operating income in our Treating division for the nine months ended September 30, 2004.
- a fixed fee for operating the plant for a certain period, which accounted for approximately 41% of the operating income for the nine month period.
- a fee arrangement in which the producer operates the plant, which accounted for approximately 4% of the operating income for the nine month period.

Typically, we incur minimal incremental operating or administrative overhead costs when gathering and transporting additional natural gas through our pipeline assets. Therefore, we recognize a substantial portion of incremental gathering and transportation margins as operating income.

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

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

We have grown significantly through asset purchases in recent years, which creates many of the major differences when comparing operating results from one period to another. We acquired the assets from Duke Energy Field Services (DEFS) in June 2003 for $68.1 million in cash. The principal assets acquired were the Mississippi pipeline system, a 638-mile natural gas gathering and transmission system in south central Mississippi, and a 12.4% non-operating interest in the Seminole gas processing plant, which provides carbon dioxide separation and sulfur removal services for major oil companies in West Texas.

In April 2004 we acquired LIG Pipeline Company and its subsidiaries (collectively, “LIG”) from a subsidiary of American Electric Power (“AEP”) for $73.5 million in cash. The principal assets acquired consist of approximately 2,000 miles of gas gathering and transmission systems located in Louisiana and five processing plants, three of which are currently idle, that have a total processing capability of 663,000 MMbtu/d. The system has a throughput capacity of 900,000 MMbtu/d and average throughput at the time of our acquisition was approximately 560,000 MMbtu/d. Customers include power plants, municipal gas systems, and industrial markets located principally in the industrial corridor between New Orleans and Baton Rouge. The LIG system is connected to several interconnected pipelines and the Jefferson Island Storage facility providing access to additional system supply. We financed the LIG acquisition through borrowings under our bank credit facility.

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 September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions, except volume amounts)			
Midstream revenues	$501.0	$276.2	$1,327.2	$745.6
Midstream purchased gas	478.5	264.0	1,266.6	715.5
Midstream gross margin	22.5	12.2	60.6	30.1
Treating revenues	7.8	7.0	22.6	17.5
Treating purchased gas	1.2	1.9	4.1	6.3
Treating gross margin	6.6	5.1	18.5	11.2
Total gross margin	$ 29.1	$ 17.3	$ 79.1	$ 41.3
Midstream Volumes (MMBtu/d):				
Gathering and transportation	1,309,000	675,000	1,285,000	643,000
Processing	428,000	134,000	419,000	126,000
Producer services	224,000	274,000	209,000	263,000
Treating Volumes (MMBtu/d)(1)	78,000	94,000	80,000	91,000

(1) Volume-sensitive plants only.

Three Months Ended September 30, 2004 Compared to Three Months Ended September 30, 2003

Gross Margin. Midstream gross margin was $22.5 million for the three months ended September 30, 2004 compared to $12.2 million for the three months ended September 30, 2003, an increase of $10.3 million, or 84%. The majority of this increase was due to the acquisition of the LIG assets on April 1, 2004, which added $8.8 million to the Midstream gross margin. The volume growth of 878 MMBtu/d, or 81%, was primarily due to the LIG assets. In addition to the volume growth, we realized higher margins on processed liquids across all of our gas plants. Basket liquid prices averaged $0.805 per gallon for third quarter 2004 compared to $0.742 per gallon for the same period in 2003, which represents a 9% increase.

Treating gross margin was $6.6 million for the three months ended September 30, 2004 compared to $5.1 million in the same period in 2003, an increase of $1.5 million, or 29%. The majority of the increase was a result of placing 38 new plants in service since September 30, 2003, which generated an additional $1.8 million in gross margin for the quarter. The increase was partially offset by a decrease in gross margin of $0.4 million due to plants that were taken out of service or plants that had reduced throughput for the comparative periods. The gross margin from the Seminole Plant increased $0.3 million during the third quarter of 2004 as compared to the corresponding quarter in 2003 due to increases in liquid prices.

Operating Expenses. Operating expenses were $10.0 million for the three months ended September 30, 2004 compared to $5.5 million for the three months ended September 30, 2003, an increase of $4.5 million, or 82%. An increase of $3.1 million was associated with the acquisition of the LIG assets. Costs for our technical services and general operations support increased by approximately $0.9 million due to staff additions to operate the LIG assets and to manage other construction projects. The 38 new treating plants in service increased operating expenses by $0.5 million.

General and Administrative Expenses. General and administrative expenses were $4.9 million for the three months ended September 30, 2004 compared to $1.7 million for the three months ended September 30, 2003, an increase of $3.2 million, or 188%. The increase was due in part to the general and administrative expense limit set by our partnership agreement for the year of 2003, which resulted in general and administrative expenses in excess of specified levels being borne by the general partner. Had the cap not been in place, general and administrative expenses would have been $2.7 million, resulting in an actual increase from 2003 to 2004 of $2.2 million. The primary reason for the increase was due to increases in wages and related costs of approximately $1.3 million for staff additions associated with the requirements of the LIG assets and growth in the Partnership's treating business. General and administrative expenses also increased due to costs associated with Sarbanes Oxley compliance totaling $0.3 million.

Stock-Based Compensation. Stock-based compensation expense decreased from $1.6 million in the third quarter of 2003 to $0.3 million in the third quarter of 2004. During 2003, certain outstanding CEI options were accounted for using variable accounting due to a "cash-out" modification offered for such options and stock compensation expense was recognized because the estimated fair value of the options increased during 2003. The "cash-out" modification offered during 2003 that caused the variable accounting treatment expired on December 31, 2003 and, effective January 1, 2004, the remaining CEI options are accounted for as fixed options. Stock-based compensation recognized in 2004 represents the amortization of costs associated with awards under long-term incentive plans, including restricted units and option grants with exercise prices below market prices on the grant date.

Gain on Sale of Property. During the third quarter of 2004, we sold one small gathering system and recognized a net gain on sale of $287,000.

Depreciation and Amortization. Depreciation and amortization expenses were $6.2 million for the three months ended September 30, 2004 compared to $4.0 million for the three months ended September 30, 2003, an increase of $2.2 million, or 55%. The increase related to the LIG assets was $1.1 million. New treating plants placed in service resulted in an increase of $0.5 million. The remaining $0.6 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Gregory Plant.

Interest Expense. Interest expense was $2.9 million for the three months ended September 30, 2004 compared to $1.3 million for the three months ended September 30, 2003, an increase of $1.6 million, or 123%. The increase relates primarily to an increase in debt outstanding and due to higher interest rates between three-month periods (weighted average rate of 6.62% in 2004 compared to 4.17% in 2003).

Net Income. Net income for the three months ended September 30, 2004 was $5.9 million compared to $3.9 million for the three months ended September 30, 2003, an increase of $2.0 million. This was generally the result of the increase in gross margin of $11.8 million between comparative quarters from 2003 to 2004, offset by increases in ongoing cash costs for operating expenses, general and administrative expenses and interest expense as discussed above. Depreciation and amortization expense also increased.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Gross Margin. Midstream gross margin was $60.6 million for the nine months ended September 30, 2004 compared to $30.1 million for the nine months ended September 30, 2003, an increase of $30.5 million, or 101%. The largest portion of this increase was due to the acquisitions of the LIG assets on April 1, 2004, and DEFS assets acquired on June 30, 2003, which added an incremental $16.9 and $5.4 million, respectively, to midstream gross margin. The volume growth of 881 MMBtu/d, or 85%, was primarily due to the acquired LIG and DEFS assets. Higher margins from strong liquid commodity prices bolstered results across all of the gas processing plants. Basket liquid prices averaged $0.867 per gallon for 2004 compared to $0.776 per gallon for 2003, which represents a 12% increase.

Treating gross margin was $18.5 million for the nine months ended September 30, 2004 compared to $11.2 million in the same period in 2003, an increase of $7.3 million, or 65%. Of this increase, $4.2 million was due to the Seminole Plant, which was one of the assets acquired from DEFS. Also contributing to the significant growth was the placement of an additional 38 plants in service since September 30, 2003. The plant additions generated $3.8 million in gross margin. These increases were partially offset by a decrease in gross margin of $0.9 million due to plants that were taken out of service or plants that had reduced throughput for the comparative periods. As mentioned previously, there are three different types of contract arrangements for our treating plants. During this nine month reporting period, the volumetric fee arrangements have decreased from 52% of operating income in 2003 to 23% in 2004, while the fixed fee plants have increased from 34% to 41% of operating income, respectively. This change provides more revenue stability, reducing the exposure to production declines and disruptions. Additionally, during this nine month reporting period, the Seminole Plant has increased from 14% of operating income in 2003 to 32% of operating income in 2004, and non-operated plants have decreased from 5% to 4% of operating income, respectively. The Seminole Plant was only in operation for three of the nine months in 2003.

Operating Expenses. Operating expenses were $26.5 million for the nine months ended September 30, 2004 compared to $12.0 million for the nine months ended September 30, 2003, an increase of $14.5 million, or 121%. Increases of $3.0 million and $6.1 million were associated with the acquisition of the DEFS and LIG assets, respectively. General operations expense was $4.0 million for 2004 compared to $1.2 million for 2003. The $2.8 million increase was related to $1.7 million in higher technical services support required by the acquired assets as well as $0.4 million of additional expenditures related to the pipeline integrity program. The growth in treating plants in service increased operating expenses by $1.9 million.

General and Administrative Expenses. General and administrative expenses were $13.2 million for the nine months ended September 30, 2004 compared to $5.1 million for the nine months ended September 30, 2003, an increase of $8.1 million, or 159%. The increase was due in part to the general and administrative expense limit set by our partnership agreement for 2003, which resulted in general and administrative expenses in excess of specified levels being borne by the general partner. Had the cap not been in place, general and administrative expenses would have been $7.2 million, resulting in an actual increase from 2003 to 2004 of $6.0 million. The increase was primarily due to increases in wages and related costs of approximately $3.3 million for staff additions associated with the requirements of the LIG and DEFS acquisitions and growth in the Partnership's treating business and its other assets as discussed above. General and administrative expenses also increased due to costs associated with Sarbanes Oxley compliance totaling $0.5 million.

Stock-Based Compensation. Stock-based compensation expense decreased from $4.6 million for the nine months ended September 30, 2003 to $0.8 million for the nine months ended September 30, 2004. During 2003, certain outstanding CEI options were accounted for using variable accounting due to a "cash-out" modification offered for such options and stock compensation expense was recognized because the estimated fair value of the options increased during 2003. The "cash-out" modification offered during 2003 that caused the variable accounting treatment expired on December 31, 2003 and, effective January 1, 2004, the remaining CEI options are accounted for as fixed options. Stock-based compensation recognized in 2004 represents the amortization of costs associated with awards under long-term incentive plans, including restricted units and option grants with exercise prices below market prices on the grant date.

(Profit) Loss on Energy Trading Activities. The profit on energy trading activities was $1.8 million for the nine months ended September 30, 2004 compared to $1.5 million for the nine months ended September 30, 2003. Included in these amounts are realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $1.5 million and $1.9 million for the nine months ended September 30, 2004 and 2003, respectively.

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

Depreciation and Amortization. Depreciation and amortization expenses were $16.5 million for the nine months ended September 30, 2004 compared to $9.1 million for the nine months ended September 30, 2003, an increase of $7.4 million, or 81%. The increase related to the DEFS assets was $2.5 million and the increase related to the LIG assets and was $2.3 million. New treating plants placed in service resulted in an increase of $1.2 million. The remaining $1.4 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Gregory Plant.

Interest Expense. Interest expense was $6.2 million for the nine months ended September 30, 2004 compared to $2.2 million for the nine months ended September 30, 2003, an increase of $4.0 million, or 182%. The increase relates primarily to an increase in debt outstanding and due to higher interest rates between nine-month periods (weighted average rate of 5.78% in 2004 compared to 5.07% in 2003).

Net Income. Net income for the nine months ended September 30, 2004 was $17.6 million compared to $9.7 million for the nine months ended September 30, 2003, an increase of $7.9 million. As detailed in each net income component above, the significant contribution of recent acquisitions impact on both the Midstream and Treating business segments, in addition to a large number of plant additions in the Treating division were the primary drivers. Existing assets continued to perform at or above expected levels. Also, higher liquid processing margins positively impacted both Midstream and Treating results.

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, 2003.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $18.9 million for the nine months ended September 30, 2004 compared to cash provided by operations of $22.3 million for the nine months ended September 30, 2003. Income before non-cash income and expenses was $34.6 million in 2004 and $23.2 million in 2003. Changes in working capital used $15.7 million in cash flows from operating activities in 2004 and $0.9 million in cash flows from operating activities in 2003. Income before non-cash income and expenses increased between periods primarily due to asset acquisitions as discussed in "Results of Operations — Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003." Changes in working capital are primarily due to the timing of collections at the end of the quarterly periods. We collect and pay large receivables and payables at the end of each calendar month and the timing of these payments and receipts may vary by a day or two between month-end periods, causing these fluctuations. Some large receivables were not collected until the first few days of October 2004 causing an increase in the use of working capital for the nine months ended September 30, 2004.

Net cash used in investing activities was $100.1 million and $98.6 million for the nine months ended September 30, 2004 and 2003, respectively. Net cash used in investing activities during 2004 related to the LIG acquisition, refurbishment and installation of treating plants, the connection of new wells to various systems, pipeline integrity projects, pipeline relocations and various other internal growth projects. During 2003, net cash used in investing activities primarily related to the DEFS acquisition and other costs related to internal growth projects including the Gregory plant expansion and buying, refurbishing and installing treating plants. Our estimated capital spending for the fourth quarter of 2004 is expected to be consistent with our expenditure levels during the second and third quarters of 2004.

Net cash provided by financing activities was $81.7 million for the nine months ended September 30, 2004 compared to $75.1 million provided by financing activities for the nine months ended September 30, 2003. Net borrowings of $93.0 million in 2004 were used to fund the LIG acquisition and the internal growth projects discussed above. Distributions to partners totaled $24.9 million in 2004, compared to distributions in 2003 of $8.4 million. Drafts payable increased by $14.4 million providing cash for financing activities for the nine months ended September 30, 2004 as compared to an increase in drafts payable of $5.8 million providing cash from financing activities for the nine months ended September 30, 2003. 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.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of September 30, 2004.

Indebtedness

As of September 30, 2004 and December 31, 2003, long-term debt consisted of the following (dollars in thousands):

	September 30, 2004	December 31, 2003
Acquisition credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at September 30, 2004 and December 31, 2003 were 4.43% and 2.92%, respectively	$ 38,000	$ 20,000
Senior secured notes, weighted average interest rate of 6.95% and 6.93% at September 30, 2004 and December 31, 2003, respectively	115,000	40,000
Note payable to Florida Gas Transmission Company	700	750
	153,700	60,750
Less current portion	50	50
Debt classified as long-term	$ 153,650	$ 60,700

In conjunction with the April 2004 acquisition of the LIG Pipeline Company and its subsidiaries discussed in Note (3) of Notes to Consolidated Financial Statements, the Partnership amended its bank credit facility to increase the borrowing base under its senior secured revolving acquisition facility from $70 million to $100 million and to increase the borrowing base under its senior secured revolving credit working capital and letter of credit facility from $50 million to $100 million. Additionally, the current ratio covenant was eliminated under this amendment. In June 2004, the bank credit facility was further amended allowing for an increase in senior secured notes to $125 million and eliminating the minimum tangible net worth covenant.

In June 2004, the Partnership completed a private placement offering of $75 million in senior secured notes with Prudential Capital Group. The notes mature in 10 years, with an average life of eight years, have an annual coupon of 6.96% and are callable after three years at 103.5% of par. The notes were used to repay borrowings under the Partnership's revolving credit facility.

As part of the $75 million private placement, the Master Shelf Agreement governing the notes was amended, the following being the significant amendments:

- increased the aggregate amount of notes that may be issued under the agreement to $125 million;

- extended the issuance period from June 2006 to June 2007;

- established a release of collateral provision should the Partnership obtain a senior unsecured debt rating of investment grade by certain rating agencies; and

- provided a call premium on the $75 million placement beginning June 2007 through June 2013 at rates declining from 3.50% to 0%. The notes are not callable prior to June 2007.

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 31E of the Securities Exchange Act of 1934, as amended. Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "forecast," "may," "believe," "will," "expect," "anticipate," "estimate," "continue" or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. In addition to specific uncertainties discussed elsewhere in this Form 10-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 55% 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; and
- 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.

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

Commodity price risk: Approximately 8.3% of the natural gas we purchase for resale is purchased on a percentage of the relevant natural gas price index, as opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. We have hedged relatively all of our exposure to gas 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 through our ability to bypass processing when it is not profitable for us. Based on the assumptions that all streams are processed each month and other variables such as shrink and plant efficiency are static, a change of $0.01 in NGL prices offset by a change of $0.10 in gas prices would create in impact on gross margin of approximately $300,000 for gas processed under these arrangements for a three-month period.

2. Percent of proceeds contracts: Under these contracts, Crosstex receives a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, 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. A change of $0.01 in NGL prices would have impacted our margins by $24,000 under such contracts for a three-month period.

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. For a three-month period, the same change of $0.01 in NGL prices offset by a change of $0.10 in gas prices would have changed our margins by $85,000 for gas processed under these arrangements.

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. Fee based contracts contributed approximately $3.2 million of gross margin for the three months ended September 30, 2004.

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. Hedges to protect our processing margins are generally for a more limited time frame than is possible for hedges in natural gas, as the financial markets for NGLs are not as developed as the markets for natural gas. Such hedges generally involve taking a short position with regard to the relevant liquids and an offsetting short position in the required volume of natural gas.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. 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. These financial transactions are marked to market against their physical offset, therefore, the margin on these transactions is recognized as profit or loss on energy trading contracts in the statement of operations. In future periods, the fair value of these transactions will result in an adjustment to the assets and liabilities recorded on the balance sheet, but there will be no additional impact on profit and loss. In addition, realized gains and losses from settled contracts are recorded in profit or loss on energy trading contracts.

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at September 30, 2004 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than December 2005, with no single contract longer than six months. Our counterparties to hedging contracts include UBS Financial, Morgan Stanley Capital Group, BP Corporation, Duke Energy Trading and Marketing and AEP Energy Services. Changes in the fair value of our derivatives related to Producer Services gas marketing activities are recorded in earnings. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings.

		September 30, 2004		
Transaction Type	**Total Volume**	**Pricing Terms**	**Remaining Term of Contracts**	**Fair Value**
				(In thousands)
Cash Flow Hedge:				
Natural gas swaps cash flow hedge	1,649,356	Fixed prices ranging from $4.85 to $7.07 settling against	October 2004 — December 2005	$ 466
Natural gas swaps cash flow hedge	(2,335,000)	various Inside FERC Index prices	October 2004 — December 2005	$ (1,791)
Total natural gas swaps cash flow hedge				$ (1,325)
Natural gas liquids (“NGLS”) swaps cash flow hedge	(2,917,404)	Fixed prices ranging from $0.5113 to $0.9975 settling against Mt. Belvieu Average of daily postings (non-TET)	October 2004 — December 2004	$ (524)
Total NGL swaps cash flow hedge				$ (524)
Swing swaps mark to market hedges(a)	3,185,000	Fixed prices ranging from $5.795 to $5.99 settling against	October 2004	$ (56)

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
		September 30, 2004		
				(In thousands)
Physical offset to Swing swaps mark to market hedges	(3,185,000)	various Inside FERC Index prices	October 2004	$ 93
Total Swing swap cash flow hedge				$ 37
Mark to Market derivatives:				
Third party on-system financial swaps	3,994,000	Fixed prices ranging from $4.83 to $6.70 settling against	October 2004 — June 2005	$ 3,891
Third party on-system financial swaps	(681,000)	various Inside FERC Index prices	October 2004 — June 2005	$ (635)
Total third party on-system financial swaps				$ 3,256
Physical offset to third party on-system transactions	681,000	Fixed prices ranging from $4.675 to $6.93 settling against	October 2004 — June 2005	$ 661
Physical offset to third party on-system transactions	(3,994,000)	various Inside FERC Index prices	October 2004 — June 2005	$ (3,607)
Total physical offset to marketing trading transactions swaps				$ (2,946)
Marketing trading financial swaps	310,000	Fixed prices ranging from $4.50 to $5.945 settling against	October 2004 — March 2005	$ 355
Marketing trading financial swaps	(450,000)	various Inside FERC Index prices	October 2004 — March 2005	$ (796)
Total marketing trading financial swaps				$ (441)
Physical offset to marketing trading transactions	450,000	Fixed prices ranging from $4.52 to $5.885 settling against	October 2004 — March 2005	$ 822
Physical offset to marketing trading transactions	(310,000)	various Inside FERC Index prices	October 2004 — March 2005	$ (350)
Total physical offset to marketing trading transactions swaps				$ 472
Fair Value hedges:				
Financial fair value hedges	(300,000)	Fixed prices ranging from $4.83 to $6.70 settling against various Inside FERC Index prices	February 2005	$ (344)
Total financial fair value hedges				$ (344)
Physical offset to fair value hedges	300,000	Fixed prices ranging from $4.675 to $6.93 settling against	September 2004	$ (1,522)
Physical offset to fair value hedges	(300,000)	various Inside FERC Index prices	February 2005	$ 2,368
Total physical offset to marketing trading transactions swaps				$ 846

(a) Swing swaps are used to hedge the price exposure we have when we buy or sell a volume of gas at a first of the month index price and the other side of the transaction is priced at a daily gas price during the month or vice versa. The swing swap functions to hedge against this exposure by buying or selling a swap to balance the quantity of gas we are buying and selling on a daily and fixed price basis.

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis.

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 September 30, 2004, we had $38.0 million of indebtedness outstanding under floating rate debt. We have interest rate swap agreements to adjust the ratio of fixed and floating rates in the debt portfolio, wherein we have swapped floating rates for fixed rates of 2.29% and the applicable margin through November 1, 2004. The impact of a 100 basis point increase in interest rates on our debt outstanding on September 30, 2004 would result in an increase in interest expense and a decrease in income before taxes of approximately $363,000 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 September 30, 2004.

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 September 30, 2004 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms.

There have been no changes in our internal controls over financial reporting that occurred during the three months ended September 30, 2004 that have materially affected, or are reasonable likely to materially affect, our internal controls over financial reporting.

PART II — OTHER INFORMATION

Item 1. *Legal Proceedings*

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. We filed a condemnation counterclaim in the District Count suit and we 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. We have timely objected to the award of the special commissioners and the condemnation case will now be tried in the County Court. The damages award by the special commissioners will have no effect and cannot be introduced as evidence in the trial. The trial court will determine the amount that we 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 trial court, we were required to post bonds and cash, each totaling the amount of $877,500, which is the amount of the special commissioners award. We are not able to predict the ultimate outcome of this matter.

Item 6. *Exhibits and Reports on Form 8-K*

(a) *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	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 29, 2004 (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.3	—	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.4	—	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).
3.5	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.6	—	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).
3.7	—	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).
3.8	—	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).
3.9	—	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).

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Number		Description
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.1 to our Registration Statement on Form S-1, file No. 333-97779).
21.1	—	List of Subsidiaries (incorporated by reference to Exhibit 21.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
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.

(b) *Reports on Form 8-K*

On July 8, 2004, Crosstex Energy, L.P. filed a Current Report on Form 8-K, Items 7 and 9, which included its press release as Exhibit 99.1 announcing that it had executed a definitive agreement, which is subject to certain closing conditions, to acquire from Williams certain onshore pipeline assets in Wharton County, Texas, for $27.4 million.

On July 23, 2004, Crosstex Energy, L.P. filed a Current Report on Form 8-K, Items 7 and 12, which reported that it would restate its annual financial statements for 2002 and certain other periods and included its press release as Exhibit 99.1 announcing the restatement.

On July 28, 2004, Crosstex Energy, L.P. filed a Current Report on Form 8-K, Items 7 and 9, which included its press release as Exhibit 99.1 announcing its second quarter distributions.

On August 10, 2004, Crosstex Energy, L.P. filed a Current Report on Form 8-K, Items 7 and 12, which included its press release as Exhibit 99.1 announcing its financial results for the three-month period ended June 30, 2004.

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 8th day of November 2004.

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

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 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)) for the registrant and have:

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

(b) 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

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

5. The registrant's other certifying 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 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: November 8, 2004

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)) for the registrant and have:

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

(b) 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

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

5. The registrant's other certifying 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 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: November 8, 2004

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 September 30, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

/s/ BARRY E. DAVIS

Barry E. Davis
Chief Executive Officer

Date: November 8, 2004

/s/ WILLIAM W. DAVIS

William W. Davis
Chief Financial Officer

Date: November 8, 2004

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.