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 March 31, 2006

OR

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

For the transition period from to

Commission file number: 000-50067

CROSSTEX ENERGY, L.P.

(Exact name of registrant as specified in its charter)

Delaware *(State of organization)*	**16-1616605** *(I.R.S. Employer Identification No.)*
2501 CEDAR SPRINGS **DALLAS, TEXAS** *(Address of principal executive offices)*	**75201** *(Zip Code)*

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

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

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

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

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

As of April 19, 2006, the Registrant had 19,549,543 common units and 7,001,000 subordinated units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	March 31, 2006 (Unaudited)	December 31, 2005
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 830	$ 1,405
Accounts and notes receivable, net:		
Trade, accrued revenue and other	345,565	442,443
Related party	107	173
Fair value of derivative assets	15,912	12,205
Prepaid expenses, natural gas and natural gas liquids in storage and other	19,203	23,549
Total current assets	381,617	479,775
Property and equipment, net of accumulated depreciation of $89,562 and $77,205, respectively	747,169	667,142
Fair value of derivative assets	6,657	7,633
Intangible assets	250,565	255,197
Goodwill	26,568	6,568
Other assets, net	8,903	8,843
Total assets	$ 1,421,479	$ 1,425,158
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and accrued gas purchases	$ 315,937	$ 437,395
Fair value of derivative liabilities	8,927	14,782
Current portion of long-term debt	8,874	6,521
Other current liabilities	34,056	32,758
Total current liabilities	367,794	491,456
Long-term debt	638,778	516,129
Deferred tax liability	8,560	8,437
Minority interest in subsidiary	4,354	4,274
Fair value of derivative liabilities	3,585	3,577
Partners' equity	398,408	401,285
Total liabilities and partners' equity	$ 1,421,479	$ 1,425,158

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Statements of Operations

	Three Months Ended March 31, 2006	2005
	(Unaudited) (In thousands, except per unit amounts)	
Revenues:		
Midstream	$ 802,130	$ 539,564
Treating	14,566	9,907
Profit on energy trading activities	423	518
Total revenues	817,119	549,989
Operating costs and expenses:		
Midstream purchased gas	755,568	516,416
Treating purchased gas	2,433	1,493
Operating expenses	21,962	11,544
General and administrative	11,355	6,460
Loss (gain) on sale of property	52	(44)
Loss (gain) on derivatives	(2,159)	474
Depreciation and amortization	17,050	6,936
Total operating costs and expenses	806,261	543,279
Operating income	10,858	6,710
Other income (expense):		
Interest expense, net	(8,512)	(3,365)
Other income	2	26
Total other income (expense)	(8,510)	(3,339)
Income before minority interest and taxes	2,348	3,371
Minority interest in subsidiary	(80)	(137)
Income tax provision	(34)	(54)
Net income before cumulative effect of change in accounting principle	2,234	3,180
Cumulative effect of change in accounting principle	689	—
Net income	$ 2,923	$ 3,180
General partner interest in net income	$ 4,165	$ 2,021
Limited partners' interest in net income (loss)	$ (1,242)	$ 1,159
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit:		
Basic	$ (0.08)	—
Diluted	$ (0.08)	—
Cumulative effect of change in accounting principle per limited partners' unit:		
Basic	$ 0.03	—
Diluted	$ 0.03	—
Net income (loss) per limited partners' unit:		
Basic	$ (0.05)	$ 0.06
Diluted	$ (0.05)	$ 0.06
Weighted average limited partners' units outstanding:		
Basic	25,550	18,098
Diluted	25,550	18,756

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Three Months Ended March 31, 2006

(Unaudited)
(In thousands except unit amounts)

	Common Units		Subordinated Units		Senior Subordinated Units		General Partner Interest		Accumulated Other Comprehensive Income	Total
	$	Units	$	Units	$	Units	$	Units		
Balance, December 31, 2005	$ 326,617	15,465,528	$ 16,462	9,334,000	$ 49,921	1,495,410	$ 11,522	536,631	$ (3,237)	$ 401,285
Stock-based compensation	313	—	111	—			531		—	955
Distributions	(7,992)	—	(4,760)	—			(4,300)	—	—	(17,052)
Conversion of subordinated units and senior subordinated units	52,195	3,828,410	(2,274)	(2,333,000)	(49,921)	(1,495,410)	—	—	—	—
Net income	(803)	—	(439)	—	—	—	4,165	—	—	2,923
Proceeds from exercise of unit options	2,525	255,605	—	—	—	—	—	—	—	2,525
Contribution by general partner	—	—	—	—	—	—	189	5,217	—	189
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	2,236	2,236
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	5,347	5,347
Balance, March 31, 2006	$ 372,855	19,549,543	$ 9,100	7,001,000	$ —	—	$ 12,107	541,848	$ 4,346	$ 398,408

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(Unaudited) (In thousands)	
Net income	$ 2,923	$ 3,180
Hedging gains or losses reclassified to earnings	2,236	(184)
Adjustment in fair value of derivatives	5,347	(4,025)
Comprehensive income (loss)	$ 10,506	$ (1,029)

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income	$ 2,923	$ 3,180
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	17,050	6,936
Non-cash stock-based compensation	1,645	276
Cumulative effect of change in accounting principle	(689)	—
(Gain) loss on sale of property	52	(44)
Deferred tax benefit	55	(95)
Minority interest in subsidiary	80	137
Non-cash derivatives (gain) loss	(995)	1,073
Amortization of debt issue costs	501	378
Changes in assets and liabilities, net of acquisition effects:		
Accounts receivable, accrued revenue and other	96,587	2,475
Prepaid expenses, natural gas and natural gas liquids in storage	4,336	(558)
Accounts payable, accrued gas purchases, and other accrued liabilities	(128,431)	(18,795)
Net cash used in operating activities	(6,886)	(5,037)
Cash flows from investing activities:		
Additions to property and equipment	(55,598)	(12,037)
Assets acquired	(51,633)	(9,257)
Proceeds from sale of property	36	193
Net cash used in investing activities	(107,195)	(21,101)
Cash flows from financing activities:		
Proceeds from borrowings	511,354	255,000
Payments on borrowings	(386,353)	(208,000)
Increase (decrease) in drafts payable	3,046	(14,202)
Contributions from general partner	189	—
Distribution to partners	(17,052)	(10,169)
Proceeds from exercise of unit options	2,525	174
Contributions from minority interest	—	911
Debt refinancing costs	(203)	(1,105)
Net cash provided by financing activities	113,506	22,609
Net increase (decrease) in cash and cash equivalents	(575)	(3,529)
Cash and cash equivalents, beginning of period	1,405	5,797
Cash and cash equivalents, end of period	$ 830	$ 2,268
Cash paid for interest	$ 9,349	$ 3,045

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements
March 31, 2006
(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 and natural gas liquids (NGL). 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 NGLs, transports natural gas and NGLs and ultimately provides an aggregated supply of natural gas to a variety of markets. In addition, the Partnership purchases natural gas and NGLs from producers not connected to its gathering systems for resale and sells natural gas on behalf of producers for a fee.

The accompanying condensed 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 condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2005.

(a) Management's Use of Estimates

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

(b) Long-Term Incentive Plans

Effective January 1, 2006, the Partnership adopted the provisions of SFAS No. 123R, *"Share-Based Compensation"* (FAS No. 123R) which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. The Partnership applied the provisions of Accounting Principles Board Opinion No. 25, *"Accounting for Stock Issued to Employees"* (APB No. 25), for periods prior to January 1, 2006.

The Partnership elected to use the modified-prospective transition method. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under FAS No. 123R. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with FAS No. 123R. The Partnership adjusted compensation cost for actual forfeitures as they occurred under APB No. 25 for periods prior to January 1, 2006. Under FAS No. 123R, the Partnership is required to estimate forfeitures in determining periodic compensation cost. The cumulative effect of the adoption of FAS No. 123R recognized on January 1, 2006 was an increase in net income of $0.7 million due to the reduction in previously recognized compensation costs associated with the estimation of forfeitures in determining the periodic compensation cost.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

The Partnership and Crosstex Energy, Inc. (CEI) each have similar share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plans awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Cost of share-based compensation charged to general and administrative expense	$ 1,479	$ 229
Cost of share-based compensation charged to operating expense	166	47
Total amount charged to income before cumulative effect of accounting change	$ 1,645	$ 276

The Partnership has a long-term incentive plan that was adopted by the Partnership's managing general partner in 2002 for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 2,600,000 common unit options and restricted units. The plan is administered by the compensation committee of the managing general partner's board of directors. The units issued upon exercise or vesting are new publicly traded common units.

Restricted Units

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the restricted units will become exercisable upon a change of control of the Partnership, its general partner, or managing general partner.

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the restricted units granted in 2005 and 2006 generally cliff vest after three years of service.

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the quarter ended March 31, 2006 is provided below:

Crosstex Energy, L.P. Restricted Units:	Three Months Ended March 31, 2006 Number of Units	Three Months Ended March 31, 2006 Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	247,648	$ 28.33
Granted	29,846	34.58
Vested	—	—
Forfeited	(12,636)	18.03
Non-vested, end of period	264,858	$ 29.53
Aggregate intrinsic value, end of period (in $000's)	$ 9,267	

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

As of March 31, 2006, there was $5.4 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.1 years.

Unit Options

Unit options will have an exercise price that, in the discretion of the compensation committee, may be less than, equal to or more than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, or its general partner, or the managing general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes- Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior. The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the contractual term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant, although a substantial portion of the unit options granted during 2004 and 2005 were granted during the second quarter of each fiscal year with an exercise price equal to the market price at the beginning of the fiscal year, resulting in an exercise price that was less than the market price at grant. The unit options granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the unit options granted in 2005 and 2006 generally vest based on 3 years of service (one-third after each year of service). The unit options have a 10-year contractual term.

Crosstex Energy, L.P. Unit Options Granted:	Three Months Ended March 31, 2006
Weighted average distribution yield	5.5%
Weighted average expected volatility	33%
Weighted average risk free interest rate	4.78%
Weighted average expected life	6.0 years
Weighted average contractual life	10 years
Weighted average of fair value of unit options granted	$ 7.44

No unit options were granted during the three months ended March 31, 2005.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

A summary of the unit option activity for the three months ended March 31, 2006 is provided below:

Crosstex Energy, L.P. Unit Options:	Three Months Ended March 31, 2006 Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	1,039,832	$ 18.88
Granted	275,403	34.59
Exercised	(255,605)	10.43
Forfeited	(20,573)	20.78
Outstanding, end of period	1,039,057	$ 25.09
Options exercisable at end of period	115,497	$ 23.82
Weighted average contractual term (years) end of period:		
Options outstanding	8.5	
Options exercisable	8.2	
Aggregate intrinsic value end of period (in 000's):		
Options outstanding	$ 10,307	
Options exercisable	$ 1,290	

The total intrinsic value of unit options exercised during the three months ended March 31, 2005 and 2006 was $0.4 million and $6.6 million, respectively. The total fair value of unit options exercised during the three months ended March 31, 2006 was $0.2 million. As of March 31, 2006, there was $3.8 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 2.5 years.

CEI Long-Term Incentive Plan

CEI has one stock-based compensation plan, the Crosstex Energy, Inc. Long-Term Incentive Plan. The plan currently permits the grant of awards covering an aggregate of 1,200,000 options for common stock and restricted shares. The plan is administered by the compensation committee of CEI's board of directors.

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. CEI's restricted stock granted prior to 2005 generally vests based on five years of service (25% in years 3 and 4 and 50% in year 5) and restricted stock granted in 2005 and 2006 generally cliff vests after three years of service.

Crosstex Energy, Inc. Restricted Shares:	Three Months Ended March 31, 2006 Number of Shares	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	196,547	$ 43.36
Granted	23,776	71.32
Vested	—	—
Forfeited	(2,050)	44.72
Non-vested, end of period	218,273	$ 46.40
Aggregate intrinsic value, end of period (in $000's)	$ 16,905	

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

No CEI stock options have been granted, exercised or forfeited attributable to officers or employees of the Partnership during the three months ended March 31, 2005 and 2006. As of March 31, 2006, following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership:

Outstanding stock options (non exercisable)		10,000
Weighted average exercise price	$	40.00
Aggregate intrinsic value	$	375,000
Weighted average remaining contractual term		8.7 years

As of March 31, 2006, there was $7.2 million of unrecognized compensation costs related to non-vested CEI restricted stock and CEI's stock options. The cost is expected to be recognized over a weighted average period of 2.3 years.

Pro Forma for 2005:

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 March 31, 2005
Net income, as reported	$	3,180
Add: Stock-based employee compensation expense included in reported net income		276
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards		(344)
Pro forma net income	$	3,112
Net income per limited partner unit, as reported:		
Basic	$	0.06
Diluted	$	0.06
Pro forma net income per limited partner unit:		
Basic	$	0.06
Diluted	$	0.06

(c) Earnings per Unit and Anti-Dilutive Computations

Basic earnings per unit was computed by dividing net income by the weighted average number of limited partner units outstanding for the three months ended March 31, 2006 and 2005. The computation of diluted earnings per unit further assumes the dilutive effect of unit options and restricted units.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three months ended March 31, 2006 and 2005 (in thousands):

	Three Months Ended March 31, 2006	2005
Basic earnings per unit:		
Weighted average limited partner units outstanding	25,550	18,098
Diluted earnings per unit:		
Weighted average limited partner units outstanding	25,550	18,098
Dilutive effect of restricted units issued	—	98
Dilutive effect of exercise of options outstanding	—	560
Dilutive effect of senior subordinated units	—	—
Diluted units	25,550	18,756

All outstanding units were included in the computation of diluted earnings per unit for the three months ended March 31, 2005. All common unit equivalents were antidilutive in the three months ended March 31, 2006 because the limited partners were allocated a net loss in this period.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note (4). The remaining net income is allocated pro rata between the 2% general partner interest and the common units. The net income allocated to the general partner for incentive distributions was $4.7 million and $2.0 million for the three months ended March 31, 2006 and 2005, respectively.

(2) Significant Asset Purchases and Acquisitions

In November 2005, the Partnership acquired El Paso Corporation’s processing and natural gas liquids business in south Louisiana for $481.0 million. The assets acquired include 2.3 billion cubic feet per day of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The Partnership financed the acquisition with net proceeds totaling $228.0 million from the issuance of common units and Senior Subordinated Series B Units (including the 2% general partner contributions totaling $4.7 million) and borrowings under its bank credit facility for the remaining balance.

Operating results for the El Paso assets have been included in the Consolidated Statements of Operations since November 1, 2005. The following unaudited pro forma results of operations assume that the El Paso acquisition occurred on January 1, 2005 (in thousands, except per unit amounts):

	Pro Forma Three Months Ended March 31, 2005
Revenue	$ 637,480
Pro forma net income	$ 2,675
Pro forma net income per common share:	
Basic	$ 0.0
Diluted	$ 0.0

We have utilized the purchase method of accounting for this acquisition with an acquisition date of November 1, 2005. The purchase price allocation for the El Paso acquisition has not been finalized because the Partnership is still in the process of finalizing working capital settlements with El Paso Corporation and estimating potential contingent obligations associated with the assets acquired. There were no significant changes to the purchase price allocation during the three months ended March 31, 2006.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

On January 2, 2005 we acquired all of the assets of Graco Operations for $9.26 million. Graco's assets consisted of 26 treating plants and associated inventory. On May 1, 2005 we acquired all of the assets of Cardinal Gas Services for $6.7 million. Cardinal's assets consisted of nine gas treating plants, 19 operating wellhead gas processing plants for dewpoint suppression, and equipment inventory.

On February 1, 2006 we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.5 million. The purchase price allocation for the Hanover assets was recorded as property, plant and equipment of $31.5 million and $20.0 million of goodwill. The Partnership is still in the process of finalizing the allocation of the purchase price at March 31, 2006. After this acquisition we have approximately 151 treating plants in operation and a total fleet of approximately 190 units.

(3) Long-Term Debt

As of March 31, 2006 and December 31, 2005, long-term debt consisted of the following (in thousands):

	March 31, 2006	December 31, 2005
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at March 31, 2006 and December 31, 2005 were 6.63% and 6.69%, respectively	$ 387,002	$ 322,000
Senior secured notes, weighted average interest rate at March 31, 2006 and December 31, 2005 of 6.57% and 6.64%, respectively	260,000	200,000
Note payable to Florida Gas Transmission Company	650	650
	647,652	522,650
Less current portion	(8,874)	(6,521)
Debt classified as long-term	$ 638,778	516,129

During 2005, the Partnership amended the bank credit facility, increasing availability under the facility to $750 million at any one time outstanding and the issuance of letters of credit in the aggregate face amount of up to $300 million at any one time. The maturity date was extended from June 2006 to November 2010.

In 2005, the Partnership amended the shelf agreement governing the senior secured notes to increase its availability from $125 million to $200 million. In March 2006 an additional amendment raised the availability under the senior secured notes to $260 million.

(4) 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 as described below 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 $4.7 million were earned by our general partner for the three months ended March 31, 2006. 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.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

The Partnership's fourth quarter distribution on its common and subordinated units of $0.51 per unit was paid on February 15, 2006. The Partnership declared a first quarter 2006 distribution of $0.53 per unit to be paid on May 15, 2006.

(5) Derivatives

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

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

In August 2005, the Partnership acquired puts, or rights to sell a portion of the liquids from the plants at a fixed price over a two-year period beginning January 1, 2006, as part of the overall risk management plan related to the acquisition of the El Paso assets. Because the underlying volumes relate to assets which, at September 30, 2005, were not yet owned by the Partnership, the puts do not qualify for hedge accounting and are marked to market through the Partnership's Consolidated Statement of Operations for the three months ended March 31, 2006.

The components of gain/loss on derivatives in the Consolidated Statements of Operations are (in thousands):

	Three Months Ended March 31, 2006	2005
Change in fair value of derivatives that do not qualify for hedge accounting gain (loss)	$ 2,084	$ (678)
Ineffective portion of derivatives qualifying for hedge accounting gain (loss)	75	204
	$ 2,159	$ (474)

The fair value of derivative assets and liabilities are as follows (in thousands):

	March 31, 2006	December 31, 2005
Fair value of derivative assets — current	$ 15,912	$ 12,205
Fair value of derivative assets — long term	6,657	7,633
Fair value of derivative liabilities — current	(8,927)	(14,782)
Fair value of derivative liabilities — long term	(3,585)	(3,577)
Net fair value of derivatives	$ 10,057	$ 1,479

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 at March 31, 2006 (all gas quantities are expressed in British Thermal Units and all liquid quantities are expressed in gallons). The remaining term of the contracts extend no later than March 2008 for derivatives, excluding third-party on-system financial swaps, and extend to October 2009 for third-party on-system financial swaps. The Partnership's counterparties to hedging contracts include BP Corporation, Total Gas & Power, Cinergy, Morgan Stanley and J. Aron & Co., a subsidiary of Goldman Sachs. Changes in the fair value of the Partnership's derivatives related to third-party producers and customers gas marketing activities are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings and the ineffective portion is recorded in earnings.

March 31, 2006				
Transaction Type	**Total Volume**	**Pricing Terms**	**Remaining Term of Contracts**	**Fair Value (In thousands)**
Cash Flow Hedges:				
Natural gas swaps	—	NYMEX less a basis of $0.01 or fixed prices ranging from $6.86 to $10.52 settling against various Inside FERC Index prices	—	$ —
Natural gas swaps	(4,068,000)		April 2006 — December 2007	3,362
Total natural gas swaps designated as cash flow hedges				$ 3,362
Liquids swaps	(37,500,770)	Fixed prices ranging from $0.64 to $1.41 settling against Mt. Belvieu Average of daily postings (non-TET)	April 2006 — December 2007	$ 1,019
Total liquids swaps designated as cash flow hedges				$ 1,019
Mark to Market Derivatives:				
Swing swaps	450,000	Prices ranging from Inside FERC Index less $0.355 to Inside FERC Index plus $0.01 settling against various Inside FERC Index prices.	April 2006	$ 79
Swing swaps	(4,316,550)		April 2006	8
Total swing swaps				$ 87
Physical offset to swing swap transactions	4,316,550	Prices of various Inside FERC Index prices settling against various Inside FERC Index prices	April 2006	—
Physical offset to swing swap transactions	(450,000)		April 2006	$ (5)
Total physical offset to swing swaps				$ (5)

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
		March 31, 2006		
Basis swaps	30,323,000	Prices ranging from Inside FERC Index less $0.40 to Inside FERC Index plus $0.18 settling against various Inside FERC Index prices.	April 2006 — March 2008	$ (76)
Basis swaps	(31,089,000)		April 2006 — March 2008	831
Total basis swaps				$ 755
Physical offset to basis swap transactions	3,698,000	Prices ranging from Inside FERC Index less $0.37 to Inside FERC Index plus $0.03 settling against various Inside FERC Index prices.	April 2006 — October 2006	$ 132
Physical offset to basis swap transactions	(3,638,000)		April 2006 — October 2006	47
Total physical offset to basis swaps				$ 179
Third party on-system financial swaps	7,235,000	Fixed prices ranging from $5.659 to $11.61 settling against various Inside FERC Index prices	April 2006 — October 2009	$ (2,623)
Third party on-system financial swaps	—		—	—
Total third party on-system financial swaps				$ (2,623)
Physical offset to third party on-system transactions	(7,235,000)	Fixed prices ranging from $5.71 to $11.71 settling against various Inside FERC Index prices	April 2006 — October 2009	$ 3,448
Physical offset to third party on-system transactions	—		—	—
Total physical offset to third party on-system swaps				$ 3,448
Storage swap transactions:				
Storage swap transactions	—	Fixed prices of $10.065 settling against various Inside FERC Index prices	—	—
Storage swap transactions	(355,000)		February 2007	$ (231)
Total financial storage swap transactions				$ (231)
Natural gas liquid puts:				
Liquid put options (purchased)	141,146,880	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu Average Daily Index	April 2006 — December 2007	$ 7,493
Liquid put options (sold)	(62,582,258)	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu Average Daily Index	April 2006 — December 2007	(3,427)
Total natural gas liquid puts				$ 4,066

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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

Impact of Cash Flow Hedges

Natural Gas

For the three months ended March 31, 2006, net losses on futures and basis swap hedge contracts decreased gas revenue by $0.5 million. For the three months ended March 31, 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $0.1 million. As of March 31, 2006, an unrealized derivative fair value gain of $3.4 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). This entire fair value gain is expected to be reclassified into earnings through December 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

The settlement of futures contracts and basis swap agreements related to April 2006 gas production increased gas revenue by approximately $0.3 million.

Liquids

For the three months ended March 31, 2006, net gains on liquids swap hedge contracts increased liquids revenue by approximately $1.1 million. For the three months ended March 31, 2006, an unrealized derivative fair value gain of $1.0 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). This entire fair value gain is expected to be reclassified into earnings in 2006 and in 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

Assets and liabilities related to third party derivative contracts, swing swaps, storage swaps and basis swaps are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as profit (loss) on energy trading activities along with the net operating results from Commercial Services in the consolidated statement of operations. The Partnership estimates the fair value of all of its energy trading contracts using prices actively quoted. The estimated fair value of energy trading contracts by maturity date was as follows (in thousands):

	Maturity Periods			
	Less Than One Year	One to Two Years	Two to Three Years	Total Fair Value
March 31, 2006	$ 3,085	$ 2,578	$ 13	$ 5,676

(6) Transactions with Related Parties

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden) and treats gas for Erskine Energy Corporation (Erskine) and Approach Resources, Inc. (Approach). All three Entities are affiliates of the Partnership by way of equity investments made by Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P., collectively a major shareholder in CEI and in Camden, Erskine and Approach. During the three months ended March 31, 2006 and 2005, the Partnership purchased natural gas from Camden in the amount of approximately $10.9 million and $9.1 million, respectively, and received approximately $0.7 and $0.8 million, respectively, in treating fees from Camden. During the three months ended March 31, 2006 the Partnership received treating fees from Erskine of $0.4 million and from Approach of $0.1 million.

(7) Commitments and Contingencies

(a) Employment Agreements

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

In conjunction with the acquisition of the Hanover assets in January 2006, the Partnership and Hanover Compressor Company on January 11, 2006 jointly filed a "Notice of Intent" for coverage under the Texas Environmental, Health and Safety Audit Privilege Act ("Audit Act") pending the asset sale transaction. Coverage under the Audit Act allows for an environmental compliance audit of the facility operations, applicable laws, regulations and permits to be conducted. Pursuant to Section 19(g) of the Audit Act, immunity for certain violations that are voluntarily disclosed as a result of a compliance audit is granted. Pursuant to Section 4(e) of the Audit Act, the audit will be completed within six months of the date of its commencement.

(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.

(8) Segment Information

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

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

The Partnership evaluates the performance of its operating segments based on earnings before income taxes, interest of non-controlling partners in the Partnership's net income and accounting changes, and after an allocation of corporate expenses. Corporate expenses and stock-based compensation are allocated to the segments on a pro rata basis based on the number of employees within the segments. Interest expense is allocated on a pro rata basis based on segment assets. Inter-segment sales are at cost.

Summarized financial information concerning the Partnership's reportable segments is shown in the following table.

	Midstream	Treating	Totals
		(In thousands)	
Three months ended March 31, 2006:			
Sales to external customers	$ 802,130	$ 14,566	$ 816,696
Inter-segment sales	2,601	(2,601)	—
Interest expense	7,239	1,273	8,512
Depreciation and amortization	14,394	2,656	17,050
Segment profit	415	1,933	2,348
Segment assets	1,285,643	135,836	1,421,479
Capital expenditures*	55,378	5,522	60,900
Three months ended March 31, 2005:			
Sales to external customers	$ 539,564	$ 9,907	$ 549,471
Inter-segment sales	1,624	(1,624)	—
Interest expense	2,755	610	3,365
Depreciation and amortization	4,597	2,339	6,936
Segment profit	2,215	1,156	3,371
Segment assets	488,206	110,090	598,296
Capital expenditures	5,429	6,608	12,037

* Excluding Acquisitions

(9) Subsequent Event

On May 2, 2006, the Partnership announced that it will acquire the natural gas gathering pipeline systems and related facilities of Chief Holdings, LLC in the Barnett Shale for $480.0 million. The Partnership expects to close the transaction by June 29, 2006.

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

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

Overview

We are a Delaware limited partnership formed by Crosstex Energy, Inc. ("CEI") on July 12, 2002 to 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 Gulf Coast of the United States and in Mississippi and Louisiana. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and natural gas liquids (NGLs), as well as providing certain producer services, while our Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the three months ended March 31, 2006, 79% of our gross margin was generated in the Midstream division, with the balance in the Treating division. We manage our business by focusing on gross margin because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas and NGLs for a fee. We buy and sell most of our gas at a fixed relationship to the relevant index price so our margins are not significantly affected by changes in gas prices. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

Since the formation of our predecessor, we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2000 through March 31, 2006, we have invested over $1.0 billion to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, and the volumes of natural gas liquids handled at our fractionation facilities. Our Treating segment margins are largely a function of the number and size of treating plants in operation and fees earned for removing impurities from natural gas liquids at a non-operated processing plant. We generate revenues from five primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants and fractionating and marketing the recovered natural gas liquids;
- treating natural gas at our treating plants;
- recovering carbon dioxide and natural gas liquids at a non-operated processing plant; and
- providing off-system marketing services for producers.

The bulk of our operating profits has historically been derived from the margins we realize for gathering and transporting natural gas through our pipeline systems. Generally, we buy gas from a producer, plant, or transporter at either a fixed discount to a market index or a percentage of the market index. We then transport and resell the gas. The resale price is based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. See "Commodity Price Risk" below for a discussion of how we manage our business to reduce the impact of price volatility.

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

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 41% and 51% of the operating income in our Treating division for the three months ended March 31, 2006 and 2005, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 41% and 44% of the operating income in our Treating division for the three months ended March 31, 2006 and 2005, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 18% and 5% of the operating income in our Treating division for the three months ended March 31, 2006 and 2005, respectively.

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

We have grown significantly through asset purchases in recent years, which creates many of the major differences when comparing operating results from one period to another. The most significant asset purchases since January 2005 were the acquisition of the El Paso Corporation processing and liquids business in southern Louisiana in November 2005, the acquisition of Graco Operations treating assets and Cardinal Gas Services treating and dewpoint control assets in January and May 2005, respectively, and the acquisition of Hanover Compression Company treating assets in February 2006.

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

On January 2, 2005, we acquired all of the assets of Graco Operations for $9.26 million. Graco's assets consisted of 26 treating plants and associated inventory. On May 1, 2005, we acquired all of the assets of Cardinal Gas Services for $6.7 million. Cardinal's assets consisted of nine gas treating plants, 19 operating wellhead gas processing plants for dewpoint suppression, and equipment inventory.

On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.5 million. After this acquisition we have approximately 151 treating plants in operation and a total fleet of approximately 190 units.

Subsequent Event

On May 2, 2006, the Partnership announced that it will acquire the natural gas gathering pipeline systems and related facilities of Chief Holdings LLC (Chief) in the Barnett Shale for $480.0 million. The Partnership expects to close the transaction by June 29, 2006.

The acquired systems consist of approximately 250 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties all of which are located in Texas. They also include a 125 million cubic feet per day CO_2 treating plant and compression facilities with 26,000 horsepower. At closing, approximately 160,000 net acres owned by Chief to be acquired by Devon simultaneously with our acquisition and 60,000 net acres owned by other producers will be dedicated to the systems.

The acquired systems have a current throughput of approximately 125 million cubic feet per day with an additional 44 million cubic feet per day awaiting pipeline connections.

The Partnership currently anticipates financing at least 50 percent of the acquisition price with newly issued subordinated units, and the remainder will be financed with debt. The subordinated units would not participate in distributions for the first eighteen months after the close, and would then convert to common units. The Partnership believes that at that point, Devon's expanded drilling program will have had an opportunity to increase production and cash flows from the system to support distributions on the subordinated units as they convert to common units. The Partnership expects to directly place up to 60 percent of these units with CEI and an additional amount directly with certain members of the Board of Directors or their affiliates. These proposed transactions are specifically subject to the approvals discussed below. It expects to place any additional units directly with institutional investors.

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 March 31, 2006	2005
	(In millions, except volume amounts)	
Midstream revenues	$ 802.1	$ 539.5
Midstream purchased gas	755.6	516.4
Profit on energy trading activities	0.4	0.5
Midstream gross margin	46.9	23.6
Treating revenues	14.6	9.9
Treating purchased gas	2.4	1.5
Treating gross margin	12.2	8.4
Total gross margin	$ 59.1	$ 32.0
Midstream Volumes (MMBtu/d):		
Gathering and transportation	1,317,524	1,273,000
Processing	1,791,740	410,000
Producer services	192,436	176,000
Treating Plants in Service	151	87

Three Months Ended March 31, 2006 Compared to Three Months Ended March 31, 2005

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $46.9 million for the three months ended March 31, 2006 compared to $23.6 million for the three months ended March 31, 2006, an increase of $23.3 million, or 99%. This increase was primarily due to acquisitions, increased system throughput, and a favorable processing environment for natural gas liquids. Profit on energy trading activities showed only a slight decline for the comparative period.

The south Louisiana natural gas processing and liquids business acquired from the El Paso Corporation in November 2005 contributed $18.6 million in gross margin in the three months ended March 31, 2006. This amount was primarily driven by the three largest plants, Eunice, Sabine Pass, and Pelican which contributed gross margin amounts of $10.4 million, $3.8 million and $3.4 million, respectively. Operational improvements and volume increases on the Mississippi system contributed margin growth of $2.6 million. Volume increases at the natural gas processing plants were the result of favorable NGLs markets. The Gibson plant and the Plaquemine plant had a combined margin increase of $2.0 million.

Treating gross margin was $12.2 million for the three months ended March 31, 2006 compared to $8.4 million in the same period in 2005, an increase of $3.8 million, or 44%. Treating plants in service increased from 87 plants in March 2005 to 151 plants in March 2006. The increase is partly due to the acquisition of the amine treating assets from Hanover Compressor Company in February of 2006 with the remainder from new plants placed in service. New plants in service contributed approximately $3.4 million in gross margin. The acquisition and installation of dew point control plants in 2005 contributed an additional $0.3 million to gross margin.

Operating Expenses. Operating expenses were $22.0 million for the three months ended March 31, 2006, compared to $11.5 million for the three months ended March 31, 2005, an increase of $10.4 million, or 90%. The acquisition of the south Louisiana assets accounted for $7.8 million of the additional operating expenses, while the net treating plant additions increased expenses by $1.5 million and the remaining increase of $1.1 million was related to higher technical services support required for the newly-acquired assets and costs associated with expansions of existing midstream assets.

General and Administrative Expenses. General and administrative expenses were $11.4 million for the three months ended March 31, 2006 compared to $6.5 million for the three months ended March 31, 2005, an increase of $4.9 million, or 76%. A substantial part of the increased expenses resulted primarily from staffing related costs of $2.8 million. The staff additions associated with the requirements of the El Paso and Hanover acquisitions accounted for the majority of the $2.8 million costs. Other expenses, including audit, legal and other consulting fees, office rent, travel and training and adjustments to the reserve for bad debt expense accounted for $0.8 million of the increase. General and administrative expenses included stock-based compensation expense of $1.5 million and $0.2 million for the three months ended March 31, 2006 and 2005, respectively. The $1.3 million increase in stock-based compensation, determined in accordance with FAS 123R during 2006 and in accordance with APB25 in 2005, primarily relates to restricted stock and unit grants made in 2005.

Gain/Loss on Derivatives. We had a gain on derivatives of $2.2 million for the three months ending March 31, 2006 compared to a loss of $0.5 million for the three months ending March 31, 2005. The gain in 2006 includes a gain of $2.3 million associated with derivatives for third-party on-system financial transactions and storage financial transactions (including $1.2 million of realized gains) and a gain of $1.0 million associated with our basis swaps partially offset by a $1.1 million loss on puts acquired in 2005 related to the acquisition of the El Paso assets. As of March 31, 2006 the fair value of the puts was $4.1 million.

Depreciation and Amortization. Depreciation and amortization expenses were $17.1 million for the three months ended March 31, 2006 compared to $6.9 million for the three months ended March 31, 2005, an increase of $10.1 million, or 146%. The primary reasons for the increase related to the south Louisiana assets purchased in November 2005 of $8.3 million and new treating plants placed in service of $1.1 million.

Interest Expense. Interest expense was $8.5 million for the three months ended March 31, 2006 compared to $3.4 million for the three months ended March 31, 2005, an increase of $5.1 million, or 153%. The increase relates primarily to an increase in debt outstanding and to higher interest rates between three-month periods (weighted average rate of 6.6% in the 2006 period compared to 6.4% in the 2005 period).

Cumulative Effect of Accounting Change. The Partnership recorded a $0.7 million cumulative adjustment to recognize the required change in reporting stock-based compensation under FASB Statement No. 123R which was effective January 1, 2006.

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, 2005.

Liquidity and Capital Resources

Cash Flows. Net cash used in operating activities was $6.9 million for the three months ended March 31, 2006 compared to cash used by operations of $5.0 million for the three months ended March 31, 2005. Income before non-cash income and expenses was $20.6 million in 2006 and $11.4 million in 2005. Changes in working capital used $27.5 million in cash flows from operating activities in 2006 and used $16.4 million in cash flows from operating activities in 2005.

Net cash used in investing activities was $107.2 million and $21.1 million for the three months ended March 31, 2006 and 2005, respectively. Net cash used in investing for the period ending March 31, 2006 consisted of $51.6 million for the Hanover acquisition, $28.8 million for the North Texas Pipeline, $10.7 million for the Parker County gathering project and $13.2 million for various other capital projects. Net cash used in investing activities during 2005 related to the $9.3 million Graco acquisition, buying, refurbishing and installing treating plants, connecting new wells to various systems, pipeline integrity, pipeline relocation and various other internal growth projects.

Net cash provided by financing activities was $113.5 million for the three months ended March 31, 2006 compared to $22.6 million used in financing activities for the three months ended March 31, 2005. Net bank borrowings of $125.0 million were used to fund activities discussed in investing activities. Distributions to partners totaled $ $17.1 million in the first quarter of 2006 compared to $10.2 million in the first quarter of 2005. Drafts payable increased by $3.0 million for the three months ended March 31, 2006 as compared to a decrease in drafts payable of $14.2 million. In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility.

Working Capital Deficit. We had a working capital deficit of $13.8 million as of March 31, 2006, primarily due to drafts payable of $32.9 million. As discussed in “Cash Flows” above, we do not borrow money to fund outstanding checks until they are presented to the bank.

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

- Maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain existing operating capacity of our assets and to extend their useful lives, or other capital expenditures which do not increase our cash flows; and
- Growth capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity, processing plants or treating plants, and to construct or acquire new pipelines, processing plants or treating plants, and expenditures made in support of that growth.

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

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.53 per quarter and to fund a portion of our anticipated capital expenditures through March 31, 2007. Total capital expenditures for the remainder of 2006 are budgeted to be approximately $67.7 million excluding the assets acquired from Chief. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

See “Subsequent Events” for discussion of the June 29, 2006 acquisition of assets from Chief.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of March 31, 2005 and 2006.

Indebtedness

As of March 31, 2006 and December 31, 2005, long-term debt consisted of the following (dollars in thousands):

	March 31, 2006	December 31, 2005
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at March 31, 2006 and December 31, 2005 were 6.63% and 6.69%, respectively	$ 387,002	$ 322,000
Senior secured notes, weighted average interest rate at March 31, 2006 and December 31, 2005 of 6.57% and 6.64%, respectively	260,000	200,000
Note payable to Florida Gas Transmission Company	650	650
	647,652	522,650
Less current portion	(8,874)	(6,521)
Debt classified as long-term	$ 638,778	$ 516,129

Credit Facility. In 2005 we amended our $200 million senior secured credit facility to increase the credit facility to provide for $750 million at any one time outstanding and the issuance of letters of credit in the aggregate face amount of up to $300 million at any one time.

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

Under the amended credit agreement, borrowings bear interest at our option at the administrative agent's reference rate plus 0% to 0.50% or LIBOR plus 1.00% to 2.00%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.00% to 2.00% per annum, plus a fronting fee of 0.125% per annum. We will incur quarterly commitment fees based on the unused amount of the credit facilities.

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

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

The credit facility contains the following covenants requiring us to maintain:

- a maximum ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, (i) 5.25 to 1.00 for any fiscal quarter ending during the period commencing on the effective date of the credit facility and ending March 31, 2006, (ii) 4.75 to 1.00 for any fiscal quarter ending during the period commencing on September 30, 2006, and (iii) 4.00 to 1.00 for any fiscal quarter ending thereafter, pro forma for any asset acquisitions (but during an acquisition adjustment period (as defined in the credit agreement), the maximum ratio is increased to 4.75 to 1); and

- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, equal to 3.0 to 1.0.

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

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

Senior Secured Notes. In June 2003, we entered into a master shelf agreement with an institutional lender pursuant to which we issued $30.0 million aggregate principal amount of senior secured notes with an interest rate of 6.95% and a maturity of seven years. In July 2003, we issued $10.0 million aggregate principal amount of senior secured notes pursuant to the master shelf agreement with an interest rate of 6.88% and a maturity of seven years. In June 2004, the master shelf agreement was amended, increasing the amount issuable under the agreement from $50.0 million to $125.0 million. In June 2004, the Partnership issued $75.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years. In June 2005, the master shelf agreement was amended, increasing the amount issuable under the agreement from $125.0 million to $200.0 million. In November 2005, we issued an $85.0 million aggregate principal amount of senior secured notes with an interest rate of 6.23% and a maturity of ten years. During March 2006 the master shelf agreement was further amended to increase the amount issuable under the agreement from $200.0 million to $260.0 million. We issued the $60.0 million aggregate principal amount of senior secured notes in March 2006 with an interest rate of 6.32% and a ten year maturity.

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

The initial $40.0 million of senior secured notes are redeemable, at our option and subject to certain notice requirements, at a purchase price equal to 100.0% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the master shelf agreement. The $75.0 million senior secured notes issued in June 2004 and the $85.0 million issued in November 2005 and the $60 million issued in March 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance.

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

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

The Partnership was in compliance with all debt covenants at March 31, 2006 and December 31, 2005 and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement, the lenders under the bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by the Partnership and its subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under the bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under the bank credit facility and the master shelf agreement.

Maturities. Maturities for the long-term debt as of March 31, 2006 are as follows (in thousands):

2006	$ 6,521
2007	10,012
2008	9,412
2009	9,412
Thereafter	612,295
Total	$ 647,652

There were no significant changes to operating leases or other contractual cash obligations during the first quarter of 2006.

Disclosure Regarding Forward-Looking Statements

This Quarterly 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;
- Tax Policy changes, such as Resulting Reported Consideration of a "Windfall Profits Tax", could have a negative impact on drilling activities, reducing natural gas available to our systems;
- our profitability is dependent upon the prices and market demand for natural gas and NGLs, which are beyond our control and have been volatile;
- we are vulnerable to operational, regulatory and other risks associated with South Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes, because we have a significant portion of our assets located in South Louisiana;
- 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;

- as of March 31, 2006, Crosstex Energy, Inc. owns approximately 38% 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 and risks of construction delay and additional costs due to difficulties in obtaining right-of-way;
- our business involves many hazards and operational risks, some of which may not be fully covered by insurance. Our operations are subject to many hazards inherent in the gathering, compressing, treating and processing of natural gas and storage of residue gas, including damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism; inadvertent damage from construction and farm equipment; leaks from natural gas, NGLs and other hydrocarbons; and fires and explosions. These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks incident to our business. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition;
- we are subject to extensive and changing federal, state and local laws and regulations designed to protect the environment, and these laws and regulations could impose liability for remediation costs and civil or criminal penalties for non-compliance;
- our common units may not have significant trading volume or liquidity, and the price of our common units may be volatile and may decline if interest rates increase; and
- cash distributions paid by us may not necessarily represent earnings.

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

Item 3. ***Quantitative and Qualitative Disclosures about Market Risk***

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

Commodity Price Risk. Approximately 7.3% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our resale margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. We have hedged approximately 62% of our exposure to gas price fluctuations through December 2006 and approximately 34% of our exposure to gas price fluctuations for the year ending December 2007. We also have hedges in place covering at least 100% of the minimum liquid volumes we expect to receive through the end of 2007 at our south Louisiana assets; and 78% of the liquids at our other assets in 2006 and 40% in 2007.

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

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

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

2. *Percent of proceeds contracts:* Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of proceeds contracts, but decline during periods of low liquid prices.

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

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

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a Risk Management Committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and natural gas liquids using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our Risk Management Committee. 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. Accordingly, the change in fair value from the previous period is reported as profit or loss on energy trading contracts in the statement of operations. In addition, realized gains and losses from settled contracts accounted for as cash flow hedges are also recorded in profit or loss on energy trading contracts. As of March 31, 2006, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments had a net fair asset value liability of $6.0 million, excluding the fair value asset of $4.1 million associated with the NGL puts. The aggregate effect of a hypothetical 10% decrease in gas and NGL prices would result in a decrease of approximately $8.1 million in the net fair value to a net liability of these contracts as of March 31, 2006 of $2.1 million. The value of the natural gas puts would also decrease as a result of an increase in NGL prices, but we are unable to determine the impact of a 10% price change. Our maximum loss on these puts is the remaining $4.1 million fair value of the puts.

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 March 31, 2006, we had $387.0 million of indebtedness outstanding under floating rate debt. The impact of a 1% increase in interest rates on our expected debt would result in an increase in interest expense and a decrease in income before taxes of approximately $3.9 million per year. This amount has been determined by considering the impact of such hypothetical interest rate increase on our non-hedged, floating rate debt outstanding at March 31, 2006.

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

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

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

Item 4. *Controls and Procedures*

(a) Evaluation of Disclosure 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 that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures as defined in 13a and 15d were effective as of March 31, 2006 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

(b) Changes in Internal control over financial reporting

There has been no change in our internal controls over financial reporting that occurred in the three months ended March 31, 2006 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART II — OTHER INFORMATION

Item 1A. ***Risk Factors***

Information about risk factors for the three months ended March 31, 2006, does not differ materially from that set forth in Part I, Item 1A, of our Annual Report on Form 10-K for the year ended December 31, 2005.

Item 6. ***Exhibits***

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

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Fourth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of November 1, 2005 (incorporated by reference to Exhibit 3.1 to our current report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
10.1	—	Letter Amendment No. 3 to Amended and Restated Master Shelf Agreement, dated as of March 13, 2006, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).
10.2	—	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).
10.3	—	Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
31.1*	—	Certification of the principal executive officer.
31.2*	—	Certification of the principal financial officer.
32.1*	—	Certification of the principal executive officer and principal financial officer of the Company pursuant to 18 U.S.C. Section 1350

* Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 9th day of May, 2006.

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 quarterly report on Form 10-Q of Crosstex Energy, L.P.;

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

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

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

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

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

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

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

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

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

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

/s/ BARRY E. DAVIS

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

Date: May 9, 2006

Exhibit 31.2

CERTIFICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

/s/ WILLIAM W. DAVIS

William W. Davis

Executive Vice President and Chief Financial Officer

(principal financial and accounting officer)

Date: May 9, 2006

Exhibit 32.1

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

In connection with the Quarterly Report of Crosstex Energy, L.P. (the “Registrant”) on Form 10-Q for the quarter ended March 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

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

May 9, 2006

/s/ WILLIAM W. DAVIS
William W. Davis
Chief Financial Officer

May 9, 2006

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.