
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, 2007

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)

**2501 CEDAR SPRINGS
DALLAS, TEXAS**
(Address of principal executive offices)

16-1616605
*(I.R.S. Employer
Identification No.)*

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 30, 2007, the Registrant had 21,989,074 common units, 4,668,000 subordinated units, 12,859,650 senior subordinated series C units and 3,875,340 senior subordinated series D units outstanding.

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CROSSTEX ENERGY, L.P.
Condensed Consolidated Balance Sheets

	March 31, 2007 (Unaudited)	December 31, 2006
(In thousands)		
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 769	\$ 824
Accounts and notes receivable, net:		
Trade, accrued revenue and other	399,634	375,972
Related party	1,219	23
Fair value of derivative assets	11,356	23,048
Natural gas and natural gas liquids, prepaid expenses and other	10,651	10,468
Total current assets	<u>423,629</u>	<u>410,335</u>
Property and equipment, net of accumulated depreciation of \$154,899 and \$136,455, respectively	1,189,622	1,105,813
Fair value of derivative assets	1,576	3,812
Intangible assets, net of accumulated amortization of \$37,835 and \$31,673, respectively	632,364	638,602
Goodwill	24,540	24,495
Other assets, net	11,071	11,417
Total assets	<u>\$ 2,282,802</u>	<u>\$ 2,194,474</u>
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and accrued gas purchases	\$ 372,952	\$ 407,718
Fair value of derivative liabilities	7,542	12,141
Current portion of long-term debt	10,012	10,012
Other current liabilities	54,774	60,400
Total current liabilities	<u>445,280</u>	<u>490,271</u>
Long-term debt	1,039,765	977,118
Deferred tax liability	9,041	8,996
Minority interest	3,674	3,654
Fair value of derivative liabilities	1,465	2,558
Commitments and contingencies	—	—
Partners' equity	783,577	711,877
Total liabilities and partners' equity	<u>\$ 2,282,802</u>	<u>\$ 2,194,474</u>

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.
Condensed Consolidated Statements of Operations

	Three Months Ended March 31,	
	2007	2006
	(Unaudited)	
	(In thousands, except per unit amounts)	
Revenues:		
Midstream	\$ 809,798	\$ 802,130
Treating	16,351	14,566
Profit on energy trading activities	603	423
Total revenues	<u>826,752</u>	<u>817,119</u>
Operating costs and expenses:		
Midstream purchased gas	751,882	756,451
Treating purchased gas	2,334	2,433
Operating expenses	27,356	21,962
General and administrative	12,034	11,355
Loss (gain) on sale of property	(850)	52
Gain on derivatives	(3,214)	(2,159)
Depreciation and amortization	24,986	17,050
Total operating costs and expenses	<u>814,528</u>	<u>807,144</u>
Operating income	12,224	9,975
Other income (expense):		
Interest expense, net	(17,326)	(8,512)
Other income	48	2
Total other income (expense)	<u>(17,278)</u>	<u>(8,510)</u>
Income (loss) before minority interest and taxes	(5,054)	1,465
Minority interest in subsidiary	(19)	(80)
Income tax provision	(204)	(34)
Net income (loss) before cumulative effect of change in accounting principle	(5,277)	1,351
Cumulative effect of change in accounting principle	—	689
Net income (loss)	<u>\$ (5,277)</u>	<u>\$ 2,040</u>
General partner interest in net income (loss)	<u>\$ 4,169</u>	<u>\$ 4,147</u>
Limited partners' interest in net income (loss)	<u>\$ (9,446)</u>	<u>\$ (2,107)</u>
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit:		
Basic	<u>\$ (0.36)</u>	<u>\$ (0.11)</u>
Diluted	<u>\$ (0.36)</u>	<u>\$ (0.11)</u>
Cumulative effect of change in accounting principle per limited partners' unit:		
Basic	<u>\$ 0.00</u>	<u>\$ 0.03</u>
Diluted	<u>\$ 0.00</u>	<u>\$ 0.03</u>
Net income (loss) per limited partners' unit:		
Basic	<u>\$ (0.36)</u>	<u>\$ (0.08)</u>
Diluted	<u>\$ (0.36)</u>	<u>\$ (0.08)</u>
Weighted average limited partners' units outstanding:		
Basic	<u>26,643</u>	<u>25,550</u>
Diluted	<u>26,643</u>	<u>25,550</u>

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.
Consolidated Statements of Changes in Partners' Equity
Three Months Ended March 31, 2007

	Common Units		Subordinated Units		Sr. Subordinated C Units		Sr. Subordinated D Units		General Partner Interest		Accumulated Other Comprehensive Income	Total
	\$	Units	\$	Units	\$	Units	\$	Units	\$	Units		
	(Unaudited)											
	(In thousands except unit amounts)											
Balance, December 31, 2006	\$ 330,492	19,616,172	\$ (6,402)	7,001,000	\$ 359,319	12,829,650	—	—	\$ 20,472	805,037	\$ 7,996	\$ 711,877
Net proceeds from issuance of senior subordinated series D units	—	—	—	—	—	—	99,900	3,875,340	—	—	—	99,900
Proceeds from exercise of unit options	829	33,170	—	—	—	—	—	—	26	677	—	855
Capital contributions	—	—	—	—	—	—	—	—	2,700	79,089	—	2,700
Conversion of subordinated units	(3,872)	2,333,000	3,872	(2,333,000)	—	—	—	—	—	—	—	—
Stock-based compensation	830	—	247	—	—	—	—	—	1,157	—	—	2,234
Distributions	(11,000)	—	(3,920)	—	—	—	—	—	(5,914)	—	—	(20,834)
Net loss	(7,300)	—	(2,146)	—	—	—	—	—	4,169	—	—	(5,277)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	(2,574)	(2,574)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	(5,304)	(5,304)
Balance, March 31, 2007	\$ 309,979	21,982,342	\$ (8,349)	4,668,000	\$ 359,319	12,829,650	\$ 99,900	3,875,340	\$ 22,610	884,803	\$ 118	\$ 783,577

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Three Months Ended March 31,	
	2007	2006
	(Unaudited)	
	(In thousands)	
Net income (loss)	\$ (5,277)	\$ 2,040
Hedging gains (losses) reclassified to earnings	(2,574)	2,236
Adjustment in fair value of derivatives	(5,304)	5,347
Comprehensive income (loss)	<u>\$ (13,155)</u>	<u>\$ 9,623</u>

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.
Consolidated Statements of Cash Flows

	Three Months Ended March 31,	
	2007	2006
	(Unaudited)	
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	\$ (5,277)	\$ 2,040
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	24,986	17,050
(Gain) loss on sale of property	(850)	52
Cumulative effect of change in accounting principle	—	(689)
Minority interest in subsidiary	19	80
Deferred tax benefit	44	55
Non-cash stock-based compensation	2,234	1,645
Non-cash derivatives (gain) loss	(477)	(995)
Amortization of debt issue costs	644	501
Changes in assets and liabilities, net of acquisition effects:		
Accounts receivable, accrued revenue and other	(24,857)	96,587
Natural gas and natural gas liquids, prepaid expenses and other	(183)	4,336
Accounts payable, accrued gas purchases and other accrued liabilities	(850)	(127,548)
Fair value of derivatives	835	—
Net cash used in operating activities	<u>(3,732)</u>	<u>(6,886)</u>
Cash flows from investing activities:		
Additions to property and equipment	(108,148)	(55,598)
Acquisitions and asset purchases	—	(51,633)
Proceeds from sale of property	1,593	36
Net cash used in investing activities	<u>(106,555)</u>	<u>(107,195)</u>
Cash flows from financing activities:		
Proceeds from borrowings	441,500	511,354
Payments on borrowings	(378,853)	(386,353)
Increase (decrease) in drafts payable	(34,738)	3,046
Debt refinancing costs	(298)	(203)
Distribution to partners	(20,834)	(17,052)
Proceeds from exercise of unit options	829	2,525
Net proceeds from issuance of subordinated units	99,900	—
Contributions from partners	2,726	189
Net cash provided by financing activities	<u>110,232</u>	<u>113,506</u>
Net increase (decrease) in cash and cash equivalents	(55)	(575)
Cash and cash equivalents, beginning of period	824	1,405
Cash and cash equivalents, end of period	<u>\$ 769</u>	<u>\$ 830</u>
Cash paid for interest	\$ 18,507	\$ 9,349

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements
March 31, 2007
(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., 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. The Partnership connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of natural gas liquids or NGLs, transports natural gas and NGLs and ultimately provides 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 and NGLs on behalf of producers for a fee.

Crosstex Energy GP, L.P. is the general partner of the Partnership. Crosstex Energy GP, L.P. is an indirect, wholly-owned subsidiary of Crosstex Energy, Inc. (CEI).

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 financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2006.

(a) Management's Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles 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 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,	
	2007	2006
Cost of share-based compensation charged to general and administrative expense	\$ 2,023	\$ 1,479
Cost of share-based compensation charged to operating expense	211	166
Total amount charged to income before cumulative effect of accounting change	<u>\$ 2,234</u>	<u>\$ 1,645</u>

Restricted Units

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 three months ended March 31, 2007 is provided below:

	Three Months Ended March 31, 2007	
	Number of Units	Weighted Average Grant-Date Fair Value
Crosstex Energy, L.P. Restricted Units:		
Non-vested, beginning of period	336,504	\$ 31.97
Granted	33,136	35.98
Vested	—	—
Forfeited	(2,200)	34.58
Non-vested, end of period	<u>367,440</u>	<u>\$ 32.32</u>
Aggregate intrinsic value, end of period (in \$000's)	<u>\$ 13,232</u>	

As of March 31, 2007, there was \$6.0 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

Unit Options

The following weighted average assumptions were used for the Black-Scholes option pricing model for grants during the three months ended March 31, 2006 and 2007:

	Three Months Ended March 31,	
	2007	2006
Crosstex Energy, L.P. Unit Options Granted:		
Weighted average distribution yield	5.75%	5.5%
Weighted average expected volatility	32%	33%
Weighted average risk free interest rate	4.44%	4.78%
Weighted average expected life	6.0 years	6.0 years
Weighted average contractual life	10.0 years	10.0 years
Weighted average of fair value of unit options granted	\$ 6.76	\$ 7.44

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

A summary of the unit option activity for the three months ended March 31, 2007 is provided below:

	Three Months Ended March 31, 2007	
	Number of Units	Weighted Average Exercise Price
Crosstex Energy, L.P. Unit Options:		
Outstanding, beginning of period	926,156	\$ 25.70
Granted	345,279	37.31
Exercised	(33,170)	24.86
Forfeited	(13,797)	23.55
Expired	(1,080)	33.59
Outstanding, end of period	<u>1,223,388</u>	<u>\$ 29.01</u>
Options exercisable at end of period	284,429	\$ 27.47
Weighted average contractual term (years) end of period:		
Options outstanding	8.3	
Options exercisable	7.8	
Aggregate intrinsic value end of period (in 000's):		
Options outstanding	\$ 9,021	
Options exercisable	\$ 2,431	

The total intrinsic value of unit options exercised during the three months ended March 31, 2006 and 2007 was \$6.6 million and \$0.5 million, respectively. The total fair value of unit options exercised during the three months ended March 31, 2006 and 2007 was \$0.2 million and \$0.2 million, respectively. As of March 31, 2007, there was \$4.1 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 2.2 years.

CEI Restricted Shares

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. A summary of the restricted share activity for the three months ended March 31, 2007 is provided below:

	Three Months Ended March 31, 2007	
	Number of Shares	Weighted Average Grant-Date Fair Value
Crosstex Energy, Inc. Restricted Shares:		
Non-vested, beginning of period	751,749	\$ 17.03
Granted	38,272	29.05
Vested	(48,750)	9.70
Forfeited	(3,051)	25.05
Non-vested, end of period	<u>738,220</u>	<u>\$ 18.10</u>
Aggregate intrinsic value, end of period (in \$000s)	<u>\$ 21,224</u>	

As of March 31, 2007, there was \$6.8 million of unrecognized compensation costs related to non-vested CEI restricted stock. The cost is expected to be recognized over a weighted average period of 1.7 years.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

CEI Stock Options

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, 2006 and 2007. As of March 31, 2007, following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership:

Outstanding stock options (non exercisable)		30,000
Weighted average exercise price	\$	13.33
Aggregate intrinsic value	\$	463,000
Weighted average remaining contractual term		7.7 years

As of March 31, 2007, there was \$51,000 of unrecognized compensation costs related to CEI's stock options and the cost is expected to be recognized over a weighted average period of 2.5 years.

(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, 2007 and 2006. The computation of diluted earnings per unit further assumes the dilutive effect of unit options and restricted units.

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, 2007 and 2006 (in thousands):

	Three Months Ended March 31,	
	2007	2006
Basic earnings per unit:		
Weighted average limited partner units outstanding	26,643	25,550
Diluted earnings per unit:		
Weighted average limited partner units outstanding	26,643	25,550
Dilutive effect of restricted units issued	—	—
Dilutive effect of exercise of options outstanding	—	—
Dilutive effect of senior subordinated units	—	—
Diluted units	<u>26,643</u>	<u>25,550</u>

All common unit equivalents were antidilutive in the three months ended March 31, 2006 and 2007 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 general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units (excluding senior subordinated units) and the common units. The net income allocated to the general partner is as follows (in thousands):

	Three Months Ended March 31,	
	2007	2006
Income allocation for incentive distributions	\$ 5,497	\$ 4,713
Stock-based compensation attributable to CEI's stock options and restricted shares	(1,135)	(522)
2% general partner interest in net income (loss)	(193)	(43)
General Partner Share of Net Income	<u>\$ 4,169</u>	<u>\$ 4,148</u>

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

(d) *Recent Accounting Pronouncements*

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes". FIN 48 is an interpretation of FASB Statement No. 109, "Accounting for Income Taxes". FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. The Partnership adopted FIN 48 effective January 1, 2007. There was no impact to the Partnership's financial statements as a result of FIN 48.

On September 13, 2006, the Securities Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (SAB 108), which establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the company's financial statements and the related disclosures. SAB 108 requires the use of a balance sheet and an income statement approach to evaluate whether either of these approaches results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The Partnership adopted SAB 108 effective October 1, 2006 with no material impact on its financial statements.

(2) *Significant Asset Purchases and Acquisitions*

On June 29, 2006, the Partnership acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale (the North Texas Gathering (NTG) assets) from Chief Holdings LLC (Chief) for a purchase price of approximately \$475.3 million (the Chief Acquisition). The NTG assets include five gathering systems, located in parts of Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties in Texas. The NTG assets also included a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. The gas gathering systems consisted of approximately 250 miles of existing gathering pipelines, ranging from four inches to twelve inches in diameter. The Partnership plans to build up to an additional 400 miles of pipelines as production in the area is drilled and developed. The gathering systems had the capacity to deliver approximately 250,000 MMBtu per day at the date of acquisition.

Simultaneously with the Chief Acquisition, the Partnership entered into a gas gathering agreement with Devon Energy Corporation (Devon) whereby the Partnership has agreed to gather, and Devon has agreed to dedicate and deliver, the future production on acreage that Devon acquired from Chief (approximately 160,000 net acres). Under the agreement, Devon has committed to deliver all of the production from the dedicated acreage into the gathering system, including production from current wells and wells that it drills in the future. The Partnership will expand the gathering system to reach the new wells as they are drilled. The agreement has a 15-year term and provides for fixed gathering fee over the term. In addition to the Devon agreement, approximately 60,000 additional net acres are dedicated to the Midstream Assets under agreements with other producers.

The Partnership utilized the purchase method of accounting for the acquisition of the Midstream Assets with an acquisition date of June 29, 2006. The Partnership will recognize the gathering fee income received from Devon and other producers who deliver gas into the Midstream Assets as revenue at the time the natural gas is delivered. The purchase price and our preliminary allocation thereof are as follows (in thousands):

Cash paid to Chief	\$ 474,858
Direct acquisition costs	429
Total purchase price	<u>\$ 475,287</u>
Assets acquired:	
Current assets	\$ 18,833
Property, plant and equipment	115,728
Intangible assets	395,604
Liabilities assumed:	
Current liabilities	<u>(54,878)</u>
Total purchase price	<u>\$ 475,287</u>

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

Intangibles relate primarily to the value of the dedicated and non-dedicated acreage attributable to the system, including the agreement with Devon, and are being amortized using the units of throughput method of amortization. The preliminary purchase price allocation has not been finalized because the Partnership is still in the process of determining the allocation of costs between tangible and intangible assets and finalizing working capital settlements.

The Partnership financed the Chief Acquisition with borrowings of approximately \$105.0 million under its bank credit facility, net proceeds of approximately \$368.3 million from the private placement of senior subordinated series C units, including approximately \$9.0 million of equity contributions from Crosstex Energy GP, L.P., the general partner of the Partnership and an indirect subsidiary of CEI, and \$6.0 million of cash.

Operating results for the Chief Acquisition have been included in the consolidated statements of operations since June 29, 2006. The following unaudited pro forma results of operations assume that the Chief Acquisition occurred on January 1, 2006 (in thousands, except per unit amounts):

	Pro Forma Three Months Ended March 31, 2006	
Revenue	\$	822,825
Net income (loss)	\$	(185)
Net income (loss) per limited partner unit:	\$	(4,288)
Basic	\$	(0.17)
Diluted	\$	(0.17)
Weighted average limited partners' units outstanding:		
Basic		25,550
Diluted		25,550

There are substantial differences in the way Chief operated the Midstream Assets during pre-acquisition periods and the way the Partnership operates these assets post-acquisition. Although the unaudited pro forma results of operations include adjustments to reflect the significant effects of the acquisition, these pro forma results do not purport to present the results of operations had the acquisition actually been completed as of January 1, 2006.

(3) Long-Term Debt

As of March 31, 2007 and December 31, 2006, long-term debt consisted of the following (in thousands):

	March 31, 2007	December 31, 2006
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at March 31, 2007 and December 31, 2006 were 7.24% and 7.20%, respectively	\$ 553,000	\$ 488,000
Senior secured notes, weighted average interest rate at March 31, 2007 and December 31, 2006 was 6.76%	496,177	498,530
Note payable to Florida Gas Transmission Company	600	600
	1,049,777	987,130
Less current portion	(10,012)	(10,012)
Debt classified as long-term	<u>\$ 1,039,765</u>	<u>\$ 977,118</u>

Credit Facility. As of March 31, 2007, the Partnership has a bank credit facility with a borrowing capacity of \$1.0 billion that matures in June 2011. As of March 31, 2007, \$632.6 million was outstanding under the bank credit facility, including \$79.6 million of letters of credit, leaving approximately \$367.4 million available for future borrowing.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

In April 2007, the Partnership amended its bank credit facility to increase the maximum permitted leverage ratio for the fiscal quarter ending September 30, 2007 and each fiscal quarter thereafter. The maximum leverage ratio (total funded debt to consolidated earnings before interest, taxes, depreciation and amortization) is as follows (provided, however, that during an acquisition period, the maximum leverage ratio shall be increased by 0.50 to 1.00 from the otherwise applicable ratio set forth below):

- 5.25 to 1.00 for fiscal quarters through December 31, 2007;
- 5.00 to 1.00 for any fiscal quarter ending March 31, 2008 through September 2008;
- 4.75 to 1.00 for fiscal quarters ending December 31, 2008 and March 31, 2009; and
- 4.50 to 1.00 for any fiscal quarter ending thereafter.

Additionally, the credit facility now provides (i) if the Partnership or its subsidiaries incur unsecured note indebtedness, the leverage ratio will shift to a two-tiered structure and (ii) during periods where the Partnership has outstanding unsecured note indebtedness, the Partnership's leverage ratio cannot exceed 5.50 to 1.00 and the Partnership's senior leverage ratio cannot exceed 4.50 to 1.00. The other material terms and conditions of the credit facility remained unchanged.

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. See note 5 to the Financial Statements for a discussion of interest rate swaps.

Senior Secured Notes. In April 2007, the Partnership amended the senior note agreement, effective as of March 30, 2007, to (i) provide that if the Partnership's leverage ratio at the end of any fiscal quarter exceeds certain limitations, the Partnership will pay the holders of the note an excess leverage fee based on the daily average outstanding principal balance of the notes during such fiscal quarter multiplied by certain percentages set forth in the senior note agreement; (ii) increase the rate of interest on each note by 0.25% if, at any given time during an acquisition period (as defined in the senior note agreement), the leverage ratio exceeds 5.25 to 1.00; (iii) cause the leverage ratio to shift to a two-tiered structure if the Partnership or its subsidiaries incur unsecured note indebtedness; and (iv) limit the Partnership's leverage ratio to 5.25 to 1.00 and the Partnership's senior leverage ratio to 4.25 to 1.00 during periods where the Partnership has outstanding unsecured note indebtedness. The other material terms and conditions of the senior note agreement remained unchanged.

The Partnership was in compliance with all debt covenants as of March 31, 2007 and expects to be in compliance with debt covenants for the next twelve months.

(4) Partners' Capital

Issuance of Senior Subordinated Series D Units

On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests of the Partnership in a private offering for net proceeds of approximately \$99.9 million. The senior subordinated series D units were issued at \$25.80 per unit, which represented a discount of approximately 25% to the market value of common units on such date. The discount represented an underwriting discount plus the fact that the units will not receive a distribution nor be readily transferable for two years. Crosstex Energy GP, L.P. made a general partner contribution of \$2.7 million in connection with this issuance to maintain its 2% general partner interest.

The senior subordinated series D units will automatically convert into common units representing limited partner interests of the Partnership on the first date on or after March 23, 2009 that conversion is permitted by its partnership agreement at a ratio of one common unit for each senior subordinated series D unit, subject to adjustment depending on the achievement of financial metrics in the fourth quarter of 2008. The Partnership's partnership agreement will permit the conversion of the senior subordinated series D units to common units once the subordination period ends or if the issuance is in connection with an acquisition that increases cash flow from operations per unit on a pro forma basis. If not able to convert on March 23, 2009, then the holders of such units will have the right to receive, after payment of the minimum quarterly distribution on the Partnership's common units

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

but prior to any payment on the Partnership's subordinated units, distributions equal to 110% of the quarterly cash distribution amount payable on common units. The senior subordinated series D units are not entitled to distributions of available cash or allocation of net income/loss from the Partnership until March 23, 2009.

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 \$5.5 million and \$4.7 million were earned by our general partner for the three months ended March 31, 2007 and 2006, respectively. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of \$0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The Partnership's fourth quarter 2006 distribution on its common and subordinated units of \$0.56 per unit was paid on February 15, 2007. The Partnership declared a first quarter 2007 distribution of \$0.56 per unit to be paid on May 15, 2007.

(5) Derivatives

Interest Rate Swaps

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. In March 2007, the Partnership entered into an interest rate swap covering a principal amount of \$50.0 million under the credit facility for a period of three years. In November 2006, the Partnership also entered into an interest rate swap covering a principal amount of \$50.0 million. The March 2007 interest rate swap fixes the three month LIBOR rate, prior to credit margin, at 4.875% on \$50.0 million of related debt outstanding over the term of the swap agreement which expires on March 31, 2010. The November 2006 interest rate swap fixes the three month LIBOR rate, prior to credit margin, at 4.95% on \$50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. The Partnership has elected to designate the March 2007 interest rate swap as a cash flow hedge for FAS 133 accounting treatment but has not yet designated the November 2006 interest rate swap as a cash flow hedge. Accordingly, unrealized gains and losses relating to the March 2007 interest rate swap are recorded in accumulated other comprehensive income until the related interest rate expense is recognized in earnings and unrealized gains and losses relating to the November 2006 interest rate swap are recorded through the consolidated statement of operations in gain on derivatives over the period hedged. At March 31, 2007, the total fair value of the interest rate swaps was a \$0.1 million liability and an unrealized loss of less than \$0.1 million was recorded in accumulated other comprehensive income. During the three months ended March 31, 2007, an unrealized gain of less than \$0.1 million was recorded in earnings and a realized gain of \$0.1 million was recorded in earnings relating to the interest rate swaps.

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Notes to Consolidated Financial Statements — (Continued)

The components of gain/loss on derivatives in the Consolidated Statements of Operations relating to interest rate swaps are (in thousands):

	Three Months Ended	
	March 31,	
	2007	2006
Change in fair value of derivatives that do not qualify for hedge accounting	\$ 17	\$ —
Realized gains (losses) on derivatives	52	—
Ineffective portion of derivatives qualifying for hedge accounting	—	—
	<u>\$ 69</u>	<u>\$ —</u>

The fair value of derivative assets and liabilities relating to interest rate swaps are as follows (in thousands):

	March 31,	December 31,
	2007	2006
Fair value of derivative assets — current	\$ 17	\$ 89
Fair value of derivative liabilities — current	(143)	—
Net fair value of derivatives	<u>\$ (126)</u>	<u>\$ 89</u>

Commodity Swaps

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 transactions include “swing swaps”, “third party on-system financial swaps”, “marketing financial swaps”, “storage swaps”, “basis swaps” and “processing margin 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. Processing margin financial swaps are used to hedge frac spread risk at our processing plants relating to the option to process versus bypassing our equity gas.

The components of gain/loss on derivatives in the Consolidated Statements of Operations, excluding interest rate swaps, are (in thousands):

	Three Months Ended March 31,	
	2007	2006
Change in fair value of derivatives that do not qualify for hedge accounting	\$ 683	\$ 920
Realized gains (losses) on derivatives	2,685	1,164
Ineffective portion of derivatives qualifying for hedge accounting	(29)	75
	<u>\$ 3,339</u>	<u>\$ 2,159</u>

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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

	March 31, 2007	December 31, 2006
Fair value of derivative assets — current	\$ 11,339	\$ 22,959
Fair value of derivative assets — long term	1,576	3,812
Fair value of derivative liabilities — current	(7,399)	(12,141)
Fair value of derivative liabilities — long term	(1,465)	(2,558)
Net fair value of derivatives	<u>\$ 4,051</u>	<u>\$ 12,072</u>

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at March 31, 2007 (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 December 2008 for derivatives, excluding third-party on-system financial swaps, and extend to June 2010 for third-party on-system financial swaps. The Partnership's counterparties to hedging contracts include BP Corporation, Total Gas & Power, Fortis, UBS Energy, 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.

Transaction type	March 31, 2007			Fair Value (In thousands)
	Total Volume	Pricing Terms	Remaining Term of Contracts	
<i>Cash Flow Hedges:</i>				
Natural gas swaps	310,500	NYMEX less a basis of \$0.785 to NYMEX less a basis of \$0.575 or fixed prices ranging from \$6.885 to \$10.855	April 2007 — December 2007	\$ 8
Natural gas swaps	(2,824,500)	settling against various Inside FERC Index prices	April 2007 — December 2008	2,246
Total natural gas swaps designated as cash flow hedges				<u>\$ 2,254</u>
Liquids swaps	(27,063,652)	Fixed prices ranging from \$0.61 to \$1.6275 settling against Mt. Belvieu Average of daily postings (non-TET)	April 2007 — March 2008	\$ (2,107)
Total liquids swaps designated as cash flow hedges				<u>\$ (2,107)</u>
<i>Mark to Market Derivatives:</i>				
Swing swaps	771,000	Prices ranging from Inside FERC Index less \$0.0025 to Inside FERC Index plus \$0.05 settling against various Gas Daily Index prices	April 2007	\$ (12)
Swing swaps	(294,000)		April 2007	(1)
Total swing swaps				<u>\$ (13)</u>
Physical offset to swing swap transactions	294,000	Prices of various Inside FERC Index prices settling against various Gas Daily Index prices	April 2007	—
Physical offset to swing swap transactions	(771,000)		April 2007	—
Total physical offset to swing swaps				<u>\$ —</u>
Basis swaps	29,881,520	NYMEX less a basis of \$0.69	April 2007 — March 2008	\$ 646

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

March 31, 2007				
Transaction type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Basis swaps	(30,684,500)	to NYMEX plus a basis of \$0.465 or prices ranging from \$9.52 to \$10.505 settling against various Inside FERC Index prices.	April 2007 — March 2008	(448)
Total basis swaps				\$ 198
Physical offset to basis swap transactions	15,900,500	Prices ranging from Inside FERC Index less \$0.38 to Inside FERC Index plus \$0.30 settling against various Inside FERC Index prices	April 2007 — October 2007	\$ (126,505)
Physical offset to basis swap transactions	(16,297,340)		April 2007 — October 2007	129,573
Total physical offset to basis swap transactions				\$ 3,068
Third party on-system financial swaps	7,354,800	Fixed prices ranging from \$5.659 to \$11.57 settling against various Inside FERC Index prices	April 2007 — June 2010	\$ 1,300
Total third party on-system financial swaps				\$ 1,300
Physical offset to third party on-system transactions	(7,354,800)	Fixed prices ranging from \$5.71 to \$11.62 settling against various Inside FERC Index prices	April 2007 — June 2010	\$ (804)
Total physical offset to third party on-system swaps				\$ (804)
<i>Natural gas liquid puts:</i>				
Liquid put options (purchased)	60,649,050	Fixed prices ranging from \$0.565 to \$1.26 settling against	April 2007 — December 2007	\$ 590
Liquid put options (sold)	(40,519,179)	Mount Belvieu Average Daily Index	April 2007 — December 2007	(435)
Total natural gas liquid puts				\$ 155

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, 2007, net gains on cash flow hedge contracts of natural gas increased gas revenue by \$1.6 million. For the three months ended March 31, 2006, net losses on cash flow hedge contracts of natural gas decreased gas revenue by \$0.5 million. As of March 31, 2007, an unrealized derivative fair value net gain of \$2.2 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). Of this net amount, a \$2.4 million gain is expected to be reclassified into earnings through March 2008. 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 cash flow hedge contracts related to April 2007 gas production increased gas revenue by approximately \$0.4 million.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

Liquids

For the three months ended March 31, 2007 and 2006, net gains on liquids swap hedge contracts increased liquids revenue by approximately \$0.5 million and \$1.1 million, respectively. For the three months ended March 31, 2007, an unrealized derivative fair value loss of \$2.1 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss) and the \$2.1 million loss is expected to be reclassified into earnings through March 2008. 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.

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, puts, swing swaps, basis swaps and storage swaps are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as gain (loss) on derivatives 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	More than two years	Total fair value
March 31, 2007	\$ 3,637	\$ 171	\$ 96	\$ 3,904

(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., in Camden, Erskine and Approach. A director of both CEI and the Partnership is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships. During the three months ended March 31, 2007 and 2006, the Partnership purchased natural gas from Camden in the amount of approximately \$7.7 million and \$10.9 million, respectively, and received approximately \$0.6 and \$0.7 million, respectively, in treating fees from Camden. During the three months ended March 31, 2007 and 2006, respectively, the Partnership received treating fees from Erskine of \$0.3 million and \$0.4 million. Treating fees of \$0.1 million were received from Approach in 2006, but the relationship was not continued in 2007.

(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's Cow Island Gas Processing Facility, which was acquired in November 2005, 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

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Notes to Consolidated Financial Statements — (Continued)

\$0.5 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.

(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 south Louisiana processing and liquids assets, the processing and transmission assets located in north and south Texas, the LIG pipelines and processing plants located in Louisiana, the Mississippi System, the Arkoma system located in Oklahoma and various other small systems. Also included in the Midstream division are the Partnership's energy trading 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 through fixed monthly payments. The Seminole carbon dioxide processing plant located in Gaines County, Texas is included in the Treating division.

The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt financing costs.

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Notes to Consolidated Financial Statements — (Continued)

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

	Midstream	Treating	Corporate	Totals
	(In thousands)			
Three months ended March 31, 2007:				
Sales to external customers	\$ 809,798	\$ 16,351	\$ —	\$ 826,149
Profit on energy trading activities	603	—	—	603
Purchased gas	(751,882)	(2,334)	—	(754,216)
Operating expenses	(22,105)	(5,251)	—	(27,356)
Segment profit	<u>\$ 36,414</u>	<u>\$ 8,766</u>	<u>\$ —</u>	<u>\$ 45,180</u>
Intersegment sales	\$ 2,646	\$ (2,646)	\$ —	\$ —
Gain (loss) on derivatives	\$ 3,349	\$ (10)	\$ (125)	\$ 3,214
Depreciation and amortization	\$ (19,790)	\$ (3,926)	\$ (1,270)	\$ (24,986)
Capital expenditures (excluding acquisitions)	\$ 91,370	\$ 10,424	\$ 1,552	\$ 103,346
Identifiable assets	\$ 2,048,375	\$ 205,602	\$ 28,825	\$ 2,282,802
Three months ended March 31, 2006:				
Sales to external customers	\$ 802,130	\$ 14,566	\$ —	\$ 816,696
Profit on energy trading activities	423	—	—	423
Purchased gas	(756,451)	(2,433)	—	(758,884)
Operating expenses	(17,476)	(4,486)	—	(21,962)
Segment profit	<u>\$ 28,626</u>	<u>\$ 7,647</u>	<u>\$ —</u>	<u>\$ 36,273</u>
Intersegment sales	\$ 2,601	\$ (2,601)	\$ —	\$ —
Gain (loss) on derivatives	\$ 2,159	\$ —	\$ —	\$ 2,159
Depreciation and amortization	\$ (13,645)	\$ (2,670)	\$ (735)	\$ (17,050)
Capital expenditures (excluding acquisitions)	\$ 53,139	\$ 6,462	\$ 1,219	\$ 60,820
Identifiable assets	\$ 1,223,601	\$ 176,120	\$ 21,758	\$ 1,421,479

The following table reconciles the segment profits reported above to the operating income as reported in the consolidated statements of operations (in thousands):

	Three Months Ended March 31,	
	2007	2006
Segment profits	\$ 45,180	\$ 36,273
General and administrative expenses	(12,034)	(11,355)
Gain (loss) on derivatives	3,214	2,159
Gain (loss) on sale of property	850	(52)
Depreciation and amortization	(24,986)	(17,050)
Operating income	<u>\$ 12,224</u>	<u>\$ 9,975</u>

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 on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. 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, 2007, 81% 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. In addition, we receive certain fees for processing based on a percentage of the liquids produced and enter into hedge contracts for our expected share of liquids produced to protect our margins from changes in liquid prices. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

During the past five years 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, 2002 through March 31, 2007, we have invested over \$1.8 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 NGLs 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 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 NGLs;
- treating natural gas at our treating plants;
- recovering carbon dioxide and NGLs 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 generally 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.

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We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 27% and 41%, including the Seminole plant, of the operating income in our Treating division for the three months ended March 31, 2007 and 2006, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 49% and 41% of the operating income in our Treating division for the three months ended March 31, 2007 and 2006, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 24% and 18% of the operating income in our Treating division for the three months ended March 31, 2007 and 2006, 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.

Acquisitions

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 2006 were the acquisition of midstream assets from Chief Holding LLC (Chief) in June 2006, the acquisition of the Hanover Compression Company treating assets in February 2006 and the acquisition of the amine-treating business of Cardinal Gas Solutions Limited Partnership in October 2006.

On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for \$475.3 million. The acquired systems consist of approximately 210 miles of existing pipeline with up to an additional 380 miles of planned pipelines in the core system build out, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties, all of which are located in Texas. The acquired assets also include a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At closing, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. Since acquisition through March 31, 2007, we had installed approximately 100 additional miles of gathering pipeline and connected 120 new wells to our gathering system. In addition to expanding our gathering system, we had installed 14,400 horsepower of additional compression to handle the increased volumes. We also added a 55,000 Mcf/d cryogenic processing plant, two 30,000 Mcf/d dew point control plants (JT plants) and added inlet refrigeration to an existing 30,000 Mcf/d plant in order to remove hydrocarbon liquids from growing gas streams. We have also installed a 40 gallons per minute amine treating facility to provide CO₂ removal capability. We have increased total throughput on this gathering system from approximately 115 MMcf/d at the time of acquisition to 265 MMcf/d for the month of March 2007.

On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for \$51.7 million.

On October 3, 2006, we acquired the amine-treating business of Cardinal Gas Solutions Limited Partnership for \$6.3 million. The acquisition added 10 dew point control plants and 50% of seven amine-treating plants to our plant portfolio. As of March 28, 2007 we acquired the remaining 50% interest in the amine-treating plants for approximately \$1.5 million.

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,	
	2007	2006
	(In millions, except volume amounts)	
Midstream revenues	\$ 809.8	\$ 802.1
Midstream purchased gas	(751.9)	(756.5)
Profit on energy trading activities	0.6	0.4
Midstream gross margin	58.5	46.0
Treating revenues	16.3	14.6
Treating purchased gas	(2.3)	(2.4)
Treating gross margin	14.0	12.2
Total gross margin	\$ 72.5	\$ 58.2
Midstream Volumes (MMBtu/d):		
Gathering and transportation	1,628,000	1,182,000
Processing	1,908,000	1,792,000
Producer services	90,000	192,000
Treating Plants, Dew Point Control and Related Equipment	198	176

Three Months Ended March 31, 2007 Compared to Three Months Ended March 31, 2006

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was \$58.5 million for the three months ended March 31, 2007 compared to \$46.0 million for the three months ended March 31, 2006, an increase of \$12.5 million, or 27%. 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 increase for the comparative period.

Crosstex acquired the North Texas Gathering (NTG) assets from Chief in June 2006. These assets combined with the North Texas Pipeline (NTPL) and related facilities contributed \$13.9 million of gross margin growth during the three months ended March 31, 2007 over the same period in 2006. The NTPL and NTG assets accounted for \$11.5 million of this increase. The processing facilities in the region contributed the additional \$2.4 million in margin growth. Operational improvements, system expansion and volume increase on the LIG system contributed margin growth of \$1.4 million during the first quarter of 2007 over the same period in 2006. The south Louisiana natural gas processing and liquids business had a gross margin decline of approximately \$2.4 million between comparative three-month periods due to lower volumes at the Eunice plant.

Treating gross margin was \$14.0 million for the three months ended March 31, 2007 compared to \$12.2 million in the same period in 2006, an increase of \$1.8 million, or 15%. Treating plants, dew point control plants, and related equipment in service increased from 176 plants at March 31, 2006 to 198 plants at March 31, 2007. Expansion projects at existing plants and plant additions from inventory contributed gross margin growth of \$1.0 million and \$0.5 million, respectively. Field services provided to producers contributed \$0.3 million in gross margin growth between comparative three month periods.

Operating Expenses. Operating expenses were \$27.4 million for the three months ended March 31, 2007, compared to \$22.0 million for the three months ended March 31, 2006, an increase of \$5.4 million, or 24.6%. A substantial part of the increase, \$4.7 million, resulted from the NTPL which commenced operation in April 2006 and the acquired Chief assets. Growth in the number of treating plants in service accounted for most of the remaining \$0.6 million increase in operating expenses. Operating expenses included stock-based compensation expense of \$0.2 million for the three months ended March 31, 2007 and 2006.

General and Administrative Expenses. General and administrative expenses were \$12.0 million for the three months ended March 31, 2007 compared to \$11.4 million for the three months ended March 31, 2006, an increase of

\$0.6 million, or 6%. The increase was attributable to stock-based compensation expense which was \$2.0 million for the three months ended March 31, 2007, up from \$1.5 million for the three months ended March 31, 2006.

Gain/Loss on Derivatives. We had a gain on derivatives of \$3.2 million for the three months ended March 31, 2007 compared to a gain of \$2.2 million for the three months ended March 31, 2006. The gain in 2007 includes a gain of \$3.7 million associated with our basis swaps (including \$0.8 million of realized gains) and a gain of \$0.5 million associated with our processing margin hedges (all realized). These were partially offset by a loss of \$0.7 million on puts acquired in 2005 related to the acquisition of the south Louisiana assets and by a net loss of \$0.2 million associated with derivatives for third-party on-system financial transactions and storage financial transactions (including \$1.4 million of realized gains). 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 south Louisiana assets. As of March 31, 2007 the fair value of the puts was \$0.2 million.

Depreciation and Amortization. Depreciation and amortization expenses were \$25.0 million for the three months ended March 31, 2007 compared to \$17.1 million for the three months ended March 31, 2006, an increase of \$7.9 million, or 46.5%. The increase in depreciation and amortization expenses related to the north Texas assets was \$5.9 million. The new treating plants acquired from Hanover, together with new treating plants placed in service, resulted in an increase of \$0.5 million. The remaining \$1.5 million increase in depreciation and amortization expenses is a result of additional assets placed in service, including new information technology systems.

Interest Expense. Interest expense was \$17.3 million for the three months ended March 31, 2007 compared to \$8.5 million for the three months ended March 31, 2006, an increase of \$8.8 million, or 104%. The increase relates primarily to an increase in debt outstanding and to higher interest rates between three-month periods (weighted average rate of 7.0% in the 2007 period compared to 6.6% in the 2006 period).

Cumulative Effect of Accounting Change. The Partnership recorded \$0.7 million of income for the 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, 2006.

Liquidity and Capital Resources

Cash Flows. Net cash used in operating activities was \$3.7 million for the three months ended March 31, 2007 compared to cash used by operations of \$6.9 million for the three months ended March 31, 2006. Income before non-cash income and expenses was \$21.3 million in 2007 and \$19.7 million in 2006. Changes in working capital used \$25.1 million in cash flows from operating activities in 2007 and used \$26.6 million in cash flows from operating activities in 2006.

Net cash used in investing activities was \$106.6 million and \$107.2 million for the three months ended March 31, 2007 and 2006, respectively. Net cash used in investing activities for the three months ended March 31, 2007 consisted of \$38.0 million for expansion in north Louisiana, \$44.5 million for north Texas transmission and gathering systems, \$10.3 million for Treating assets, \$9.0 million for various other capital projects and \$4.8 million to pay liabilities accrued for property and equipment expenditures as of December 31, 2006. Net cash used in investing activities for the three months ended March 31, 2006 consisted of \$51.6 million for the Hanover acquisition, \$28.8 million for the NTPL, \$10.7 million for the Parker County gathering project and \$13.2 million for various other capital projects.

Net cash provided by financing activities was \$110.2 million for the three months ended March 31, 2007 compared to \$113.5 million provided by financing activities for the three months ended March 31, 2006. Net cash provided by financing activities for the three months ended March 31, 2007 included \$102.6 million from the issuance of senior subordinated series D units, including the general partner contribution and net of issuance costs, and net bank borrowings of \$62.6 million. Net cash provided by financing activities for the three months ended March 31, 2006 included net bank borrowings of \$125.0 million. Distributions to partners totaled \$20.8 million in

the first quarter of 2007 compared to \$17.1 million in the first quarter of 2006. Drafts payable increased by \$3.0 million for the three months ended March 31, 2006 as compared to a decrease in drafts payable of \$34.7 million for the three months ended March 31, 2007. In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility.

Working Capital Deficit. We had a working capital deficit of \$21.7 million as of March 31, 2007, primarily due to drafts payable of \$13.2 million and accrued liabilities of \$54.8 million, including \$24.4 million attributable to accrued property development costs. As discussed in "Cash Flows" above, we do not borrow money to fund outstanding checks until they are presented to the bank. We borrow money under our \$1.0 billion credit facility to fund checks as they are presented. As of March 31, 2007, we had approximately \$367.4 million of available borrowing capacity under this facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of March 31, 2007 and 2006.

March 2007 Sale of Senior Subordinated Series D Units. On March 23, 2007, we issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests in a private offering for net proceeds of approximately \$99.9 million. The senior subordinated series D units were issued at \$25.80 per unit, which represented a discount of approximately 25% to the market value of common units on such date. The discount represented an underwriting discount plus the fact that the units will not receive a distribution nor be readily transferable for two years. Crosstex Energy GP, L.P. made a general partner contribution of \$2.7 million in connection with this issuance to maintain its 2% general partner interest. The senior subordinated series D units will automatically convert into common units representing limited partner interests on the first date on or after March 23, 2009 that conversion is permitted by our partnership agreement at a ratio of one common unit for each senior subordinated series D unit, subject to adjustment depending on the achievement of financial metrics in the fourth quarter of 2008. The senior subordinated series D units are not entitled to distributions of available cash or allocations of net income/loss from us until March 23, 2009.

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 and large capital expansions, we anticipate that we will continue to invest significant amounts of capital to grow and to build and acquire assets. We actively consider a variety of assets for potential development and acquisitions.

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of \$0.56 per quarter and to fund a portion of our anticipated capital expenditures through March 31, 2008. Total capital expenditures for the remainder of 2007 are budgeted to be approximately \$150.0 million. 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.

Indebtedness

As of March 31, 2007 and December 31, 2006, long-term debt consisted of the following (dollars in thousands):

	March 31, 2007	December 31, 2006
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at March 31, 2007 and December 31, 2006 were 7.24% and 7.20%, respectively	\$ 553,000	\$ 488,000
Senior secured notes, weighted average interest rate at March 31, 2007 and December 31, 2006 was 6.76%	496,177	498,530
Note payable to Florida Gas Transmission Company	600	600
	<u>1,049,777</u>	<u>987,130</u>
Less current portion	(10,012)	(10,012)
Debt classified as long-term	<u>\$ 1,039,765</u>	<u>\$ 977,118</u>

Credit Facility.

As of March 31, 2007, we had a bank credit facility with a borrowing capacity of \$1.0 billion that matures in June 2011. As of March 31, 2007, \$632.6 million was outstanding under the bank credit facility, including \$79.6 million of letters of credit, leaving approximately \$367.4 million available for future borrowing.

In April 2007, we amended our bank credit facility to increase the maximum permitted leverage ratio for the fiscal quarter ending September 30, 2007 and each fiscal quarter thereafter. The maximum leverage ratio (total funded debt to consolidated earnings before interest, taxes, depreciation and amortization) is as follows (provided, however, that during an acquisition period, the maximum leverage ratio shall be increased by 0.50 to 1.00 from the otherwise applicable ratio set forth below):

- 5.25 to 1.00 for fiscal quarters through December 31, 2007;
- 5.00 to 1.00 for any fiscal quarter ending March 31, 2008 through September 2008;
- 4.75 to 1.00 for fiscal quarters ending December 31, 2008 and March 31, 2009; and
- 4.50 to 1.00 for any fiscal quarter ending thereafter.

Additionally, the credit facility now provides (i) if we or our subsidiaries incur unsecured note indebtedness, the leverage ratio will shift to a two-tiered structure and (ii) during periods where we have outstanding unsecured note indebtedness, our leverage ratio cannot exceed 5.50 to 1.00 and our senior leverage ratio cannot exceed 4.50 to 1.00. The other material terms and conditions of the credit facility remain unchanged.

Senior Secured Notes. In April 2007, we amended our senior note agreement, effective as of March 30, 2007, to (i) provide that if our leverage ratio at the end of any fiscal quarter exceeds certain limitations, we will pay the holders of the note an excess leverage fee based on the daily average outstanding principal balance of the notes during such fiscal quarter multiplied by certain percentages set forth in the senior note agreement; (ii) increase the rate of interest on each note by 0.25% if, at any given time during an acquisition period (as defined in the senior note agreement), the leverage ratio exceeds 5.25 to 1.00; (iii) cause the leverage ratio to shift to a two-tiered structure if we or our subsidiaries incur unsecured note indebtedness, and (iv) limit our leverage ratio to 5.25 to 1.00 and our senior leverage ratio to 4.25 to 1.00 during periods where we have outstanding unsecured note indebtedness. The other material items and conditions of the senior note agreement remained unchanged.

We were in compliance with all debt covenants as of March 31, 2007 and expect to be in compliance with debt covenants for the next twelve months.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of March 31, 2007, is as follows:

	Total	Payments Due by Period					Thereafter
		2007	2008	2009 (In millions)	2010	2011	
Long-term debt	\$ 1,049.8	\$ 7.7	\$ 9.4	\$ 9.4	\$ 20.3	\$ 585.0	\$ 418.0
Capital lease obligations Operating leases	99.2	14.3	18.0	17.2	16.1	16.0	17.6
Unconditional purchase obligations	—	—	—	—	—	—	—
Other long-term obligations	—	—	—	—	—	—	—
Total contractual obligations	\$ 1,149.0	\$ 22.0	\$ 27.4	\$ 26.6	\$ 36.4	\$ 601.0	\$ 435.6

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

The Partnership was in compliance with all debt covenants at March 31, 2007 and December 31, 2006 and expects to be in compliance with debt covenants for the next twelve months.

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 21E of the Securities Exchange Act of 1934, as amended that are based on information currently available to management as well as management’s assumptions and beliefs. Statements included in this report which are not historical facts 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. Such statements reflect our current views with respect to future events based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to specific uncertainties discussed elsewhere in this Form 10-Q, the risk factors set forth in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2006, and those set forth in Part II, “Item 1A. Risk Factors” of this report may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas and NGLs. In addition, we are also exposed to the risk of changes in interest rates on our floating rate debt.

Interest Rate Risk

We are exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At March 31, 2007, our variable rate debt had a carrying value of \$553.6 million which approximated its fair value, and our fixed rate debt had a carrying value of \$496.2 million with an approximate fair value of \$501.3 million. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk. This is accomplished through a mix of bank debt with short-term variable rates and fixed rate senior and subordinated debt. In addition, we have entered into two separate interest rate swaps covering principal amounts of \$50.0 million each under the credit facility for periods of three years each. The interest rate swaps reduce our risk by fixing the three month LIBOR rate over the term of the swap agreement.

In November 2006, we entered into an interest rate swap that fixed the three month LIBOR rate, prior to credit margin, at 4.95% on \$50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. The fair value of the interest rate swap at March 31, 2007 was a \$0.1 million liability.

In March 2007, we entered into an interest rate swap that fixed the three month LIBOR rate, prior to credit margin, at 4.875% on \$50.0 million of related debt outstanding over the term of the swap agreement which expires on March 31, 2010. The fair value of the interest rate swap at March 31, 2007 was a liability of less than \$0.1 million.

The following table shows the carrying amount and fair value of long-term debt and the hypothetical change in fair value that would result from a 100-basis point change in interest rates. Unless otherwise noted, the hypothetical change in fair value could be a gain or a loss depending on whether interest rates increase or decrease.

	<u>Carrying Amount</u> (In millions)	<u>Fair Value(a)</u>	<u>Hypothetical Change in Fair Value</u>
March 31, 2007	\$ 1,049.8	\$ 1,059.4	\$ 9.6

(a) Fair value is based upon current market quotes and is the estimated amount required to purchase our long-term debt on the open market. This estimated value does not include any redemption premium.

Commodity Price Risk

Approximately 4% 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 natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices. As of March 31, 2007, we have hedged approximately 81% of our exposure to natural gas price fluctuations through March 2008 and approximately 20% of our exposure to natural gas price fluctuations for April 2008 — December 2008. We also have hedges in place covering 79% of the liquid volumes we expect to receive at our south Louisiana assets through the end of 2007 and approximately 80% for the first quarter of 2008; and 74% of the liquids at our other assets through the end of 2007 and 80% for the first quarter of 2008.

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 substantially on the same basis. However, it is normal to experience fluctuations in the volumes of gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

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

1. Keep-whole contracts: Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost (shrink) in processing. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. We control our risk on our current keep-whole contracts primarily through our ability to bypass processing when it is not profitable for us.
2. Percent of proceeds contracts: Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of proceeds contracts, but decline during periods of low NGL prices.
3. Theoretical processing contracts: Under these contracts, we stipulate with the producer the assumptions under which we will assume processing economics for settlement purposes, independent of actual processing results or whether the stream was actually processed. These contracts tend to have an inverse result to the keep-whole contracts, with better margins as processing economics worsen.
4. Fee based contracts: Under these contracts we have no commodity price exposure, and are paid a fixed fee per unit of volume that is treated or conditioned.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a Risk Management Committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLs using NYMEX futures or over-the-counter derivative financial

instruments with only certain well-capitalized counterparties which have been approved by our Risk Management Committee.

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

We manage our price risk related to future physical purchase or sale commitments for our commercial 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 credit risk for both the physical and financial contracts. We account for certain of our commercial 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 arising from changes to the fair market value of the derivative and physical delivery contract related to our producer services natural gas marketing activities are recognized in earnings as profit or loss from 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 a gain or loss on derivatives in the statement of operations. Realized gains and losses from settled contracts accounted for as cash flow hedges are recorded in Midstream Revenue. As of March 31, 2007, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements and other derivative instruments were a net fair value asset of \$3.9 million, excluding the fair value asset of \$0.2 million associated with the natural gas liquids puts. The aggregate effect of a hypothetical 10% increase in gas and NGLs prices would result in a decrease of approximately \$4.7 million in the net fair value asset of these contracts as of March 31, 2007. The value of the natural gas liquids puts would also decrease as a result of an increase in NGLs prices but we are unable to determine the impact of a 10% price change. Our maximum loss on these puts is the remaining \$0.2 million recorded fair value for the puts.

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 were effective as of March 31, 2007 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, 2007 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, 2007, 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, 2006.

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	— Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our current report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
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	— Third Amendment to Fourth Amended and Restated Credit Agreement, effective March 30, 2007, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.2	— Letter Amendment No. 1 to Amended and Restated Note Purchase Agreement, effective March 30, 2007, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.3	— Senior Subordinated Series D Unit Purchase Agreement dated as of March 30, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 27, 2007, filed with the Commission on April 5, 2007).
10.4	— Registration Rights Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
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, 2007.

CROSTEX 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

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, 2007

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, 2007

**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, 2007 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, 2007

/s/ WILLIAM W. DAVIS

William W. Davis
Chief Financial Officer

May 9, 2007

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.