SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended June 30, 2006

OR

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

For the transition period from to

Commission file number: 000-50067

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

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

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

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

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

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

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

As of July 31, 2006, the Registrant had 19,598,113 common units, 7,001,000 subordinated units, and 12,829,650 senior subordinated C units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	June 30, 2006 (Unaudited)	December 31, 2005
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 921	$ 1,405
Accounts and notes receivable, net:		
Trade, accrued revenue, and other	294,784	442,443
Related party	127	173
Fair value of derivative assets	20,967	12,205
Natural gas and natural gas liquids in storage, prepaid expenses and other	30,980	23,549
Total current assets	347,779	479,775
Property and equipment, net of accumulated depreciation of $103,029 and $77,205, respectively	879,374	667,142
Fair value of derivatives assets	3,850	7,633
Intangible assets, net	670,601	255,197
Goodwill	23,074	6,568
Other assets, net	12,790	8,843
Total assets	$ 1,937,468	$ 1,425,158
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and accrued gas purchases	$ 321,302	$ 437,395
Fair value of derivative liabilities	18,816	14,782
Current portion of long-term debt	10,012	6,521
Other current liabilities	17,237	32,758
Total current liabilities	367,367	491,456
Fair value of derivative liabilities	3,341	3,577
Long-term debt	808,825	516,129
Deferred tax liability	8,815	8,437
Minority interest in subsidiary	4,455	4,274
Partners' equity	744,665	401,285
Total liabilities and partners' equity	$ 1,937,468	$ 1,425,158

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(Unaudited) (In thousands, except per unit amounts)			
Revenues:				
Midstream	$ 727,865	$ 619,432	$ 1,529,996	$ 1,158,996
Treating	15,983	11,040	30,549	20,947
Profit on energy trading activities	807	333	1,230	851
Total revenues	744,655	630,805	1,561,775	1,180,794
Operating costs and expenses:				
Midstream purchased gas	676,370	594,482	1,431,938	1,110,898
Treating purchased gas	2,056	1,711	4,489	3,204
Operating expenses	22,840	12,178	44,801	23,722
General and administrative	10,919	7,750	22,275	14,211
Gain on sale of property	(160)	(120)	(109)	(164)
Loss (gain) on derivatives	3,925	(66)	1,766	407
Depreciation and amortization	18,708	7,370	35,758	14,306
Total operating costs and expenses	734,658	623,305	1,540,918	1,166,584
Operating income	9,997	7,500	20,857	14,210
Other income (expense):				
Interest expense, net	(11,890)	(3,196)	(20,402)	(6,561)
Other	(1)	322	—	348
Total other income (expense)	(11,891)	(2,874)	(20,402)	(6,213)
Income (loss) before minority interest and taxes	(1,894)	4,626	455	7,997
Minority interest in subsidiary	(101)	(88)	(182)	(225)
Income tax provision	(264)	(54)	(298)	(108)
Net income (loss) before cumulative effect of change in accounting principle	(2,259)	4,484	(25)	7,664
Cumulative effect of change in accounting principle	—	—	689	—
Net income (loss)	$ (2,259)	$ 4,484	$ 664	$ 7,664
General partner interest in net income	$ 3,890	$ 1,205	$ 8,056	$ 3,226
Limited partners' interest in net income (loss)	$ (6,149)	$ 3,279	$ (7,392)	$ 4,438
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit:				
Basic	$ (0.23)	$ 0.18	$ (0.31)	$ 0.25
Diluted	$ (0.23)	$ 0.17	$ (0.31)	$ 0.24
Cumulative effect of change in accounting principle per limited partners' unit:				
Basic	—	—	$ 0.03	—
Diluted	—	—	$ 0.03	—
Net income (loss) per limited partners' unit:				
Basic	$ (0.23)	$ 0.18	$ (0.28)	$ 0.25
Diluted	$ (0.23)	$ 0.17	$ (0.28)	$ 0.24
Weighted average limited partners' units outstanding:				
Basic	26,572	18,124	26,064	18,111
Diluted	26,572	18,880	26,064	18,819

See accompanying notes to consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Six Months ended June 30, 2006

	Common Units		Subordinated Units		Sr. Subordinated Units		Sr. Subordinated C Units		General Partner Interest		Accumulated Other Comprehensive Income	Total
	$	Units	$	Units	$	Units	$	Units	$	Units		
						(Unaudited) (In thousands, except unit amounts)						
Balance, December 31, 2005	$ 326,617	15,465,528	$ 16,462	9,334,000	$ 49,921	1,495,410	—	—	$ 11,522	536,631	$ (3,237)	$ 401,285
Proceeds from exercise of unit options	2,821	271,552	—	—	—	—	—	—	—	—	—	2,821
Net proceeds from issuance of senior subordinated C units	—	—	—	—	—	—	$ 359,400	12,829,650	—	—	—	359,400
Conversion of units	52,195	3,828,410	(2,274)	(2,333,000)	(49,921)	(1,495,410)	—	—	—	—	—	—
Common units for restricted units	—	19,500	—	—	—	—	—	—	—	—	—	—
Capital contributions	—	—	—	—	—	—	—	—	9,253	267,770	—	9,253
Stock-based compensation	1,234	—	440	—	—	—	—	—	1,519	—	—	3,193
Distributions	(18,354)	—	(8,471)	—	—	—	—	—	(9,397)	—	—	(36,222)
Net income (loss)	(5,333)	—	(2,059)	—	—	—	—	—	8,056	—	—	664
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	1,440	1,440
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	2,831	2,831
Balance, June 30, 2006	$ 359,180	19,584,990	$ 4,098	7,001,000	—	—	$ 359,400	12,829,650	$ 20,953	804,401	$ 1,034	$ 744,665

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(Unaudited) (In thousands)	
Net income	$ 664	$ 7,664
Hedging gains or losses reclassified to earnings	1,440	882
Adjustment in fair value of derivatives	2,831	(3,292)
Comprehensive income	$ 4,935	$ 5,254

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income	$ 664	$ 7,664
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	35,758	14,306
Non-cash stock-based compensation	3,882	1,130
Cumulative effect of change in accounting principle	(689)	—
Gain on sale of property	(109)	(164)
Deferred tax (benefit) expense	291	(190)
Minority interest in subsidiary	182	225
Non-cash derivatives loss	3,090	996
Amortization of debt issue costs	1,433	561
Changes in assets and liabilities, net of acquisition effects:		
Accounts receivable, accrued revenue, and other	165,795	12,659
Prepaid expenses, natural gas and natural gas liquids in storage	(7,424)	(1,830)
Accounts payable, accrued gas purchases, and other accrued liabilities	(165,185)	(20,039)
Net cash provided by operating activities	37,688	15,318
Cash flows from investing activities:		
Additions to property and equipment	(97,885)	(25,780)
Assets acquired	(552,751)	(15,969)
Proceeds from sale of property	197	313
Net cash used in investing activities	(650,439)	(41,436)
Cash flows from financing activities:		
Proceeds from borrowings	995,892	457,750
Payments on borrowings	(699,706)	(453,800)
Decrease in drafts payable	(14,063)	(12,694)
Proceeds from issuance of senior subordinated units	359,400	49,950
Capital contributions	9,249	1,528
Contributions from minority interest	—	1,287
Distribution to partners	(36,222)	(20,716)
Proceeds from exercise of unit options	2,824	562
Debt refinancing costs	(5,107)	(1,217)
Net cash provided by financing activities	612,267	22,650
Net decrease in cash and cash equivalents	(484)	(3,468)
Cash and cash equivalents, beginning of period	1,405	5,797
Cash and cash equivalents, end of period	$ 921	$ 2,329
Cash paid for interest	$ 21,023	$ 6,096

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements
June 30, 2006
(Unaudited)

(1) General

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

Crosstex Energy, L.P. (the "Partnership"), a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids. The Partnership connects the wells of natural gas producers in its market areas to its gathering systems, 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. The Partnership purchases natural gas from natural gas producers and other supply points and sells that natural gas to utilities, industrial customers, other marketers and pipelines and thereby generates gross margins based on the difference between the purchase and resale prices. 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, 2005. Certain reclassifications have been made to the consolidated financial statements for the prior year periods to conform to the current presentation.

(a) Management's Use of Estimates

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

(b) Long-Term Incentive Plans

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.

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 June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Cost of share-based compensation charged to general and administrative expense	$ 1,919	$ 1,080	$ 3,397	$ 1,309
Cost of share-based compensation charged to operating expense	318	162	485	208
Total amount charged to income before cumulative effect of accounting change	$ 2,237	$ 1,242	$ 3,882	$ 1,517

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

Restricted Units

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

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

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the quarter ended June 30, 2006 is provided below:

	Six Months Ended June 30, 2006	
	Number of Units	Weighted Average Grant-Date Fair Value
Crosstex Energy, L.P. Restricted Units:		
Non-vested, beginning of period	247,648	$ 28.33
Granted	108,774	$ 34.20
Vested	(19,500)	$ 12.99
Forfeited	(19,256)	$ 24.41
Non-vested, end of period	317,666	$ 31.52
Aggregate intrinsic value, end of period (in thousands)	$ 11,684	

The aggregate intrinsic value of vested units for both the three and six months ended June 30, 2006 was $0.7 million. As of June 30, 2006, there was $6.9 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.1 years.

Unit Options

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Crosstex Energy, L.P. Unit Options Granted:				
Weighted average distribution yield	5.5%	5.0%	5.5%	5.0%
Weighted average expected volatility	32.9%	33.0%	33.0%	33.0%
Weighted average risk free interest rate	4.97%	3.70%	4.79%	3.70%
Weighted average expected life	6 years	3 years	6 years	3 years
Weighted average contractual life	10 years	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$ 7.37	$ 7.93	$ 7.45	$ 7.93

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

A summary of the unit option activity for the six months ended June 30, 2006 is provided below:

	Six Months Ended June 30, 2006	
	Number of Units	Weighted Average Exercise Price
Crosstex Energy, L.P. Unit Options:		
Outstanding, beginning of period	1,039,832	$ 18.88
Granted	285,403	34.61
Exercised	(271,552)	10.57
Forfeited	(56,016)	23.08
Outstanding, end of period	997,667	$ 25.41
Options exercisable at end of period	137,298	$ 21.19
Weighted average contractual term (years) end of period:		
Options outstanding	8.3	
Options exercisable	7.8	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 11,346	
Options exercisable	$ 2,140	

The total intrinsic value of unit options exercised during the six months ended June 30, 2005 and 2006 was $1.4 million and $7.0 million, respectively. The intrinsic value of unit options exercised during the three months ended June 30, 2005 and 2006 was $1.0 million and $0.4 million, respectively. As of June 30, 2006, there was $3.4 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 2.3 years.

CEI Long-Term Incentive Plan

CEI has one stock-based compensation plan, the Crosstex Energy, Inc. Long-Term Incentive Plan. The plan currently permits the grant of awards covering an aggregate of 1,200,000 options for common stock and restricted shares. The plan is administered by the compensation committee of CEI's board of directors. The shares issued upon exercise or vesting are newly issued common 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. CEI's restricted stock granted prior to 2005 generally vests based on five years of service (25% in years 3 and 4 and 50% in year 5) and restricted stock granted in 2005 and 2006 generally cliff vests after three years of service.

	Six Months Ended June 30, 2006	
	Number of Shares	Weighted Average Grant-Date Fair Value
Crosstex Energy, Inc. Restricted Shares:		
Non-vested, beginning of period	196,547	$ 43.36
Granted	53,864	$ 72.00
Vested	—	—
Forfeited	(6,739)	$ 47.77
Non-vested, end of period	243,672	$ 49.57
Aggregate intrinsic value, end of period (in thousands)	$ 23,168	

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

No CEI stock options have been granted to, or exercised or forfeited by, any officers or employees of the Partnership during the six months ended June 30, 2005 and 2006. The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of June 30, 2006:

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

As of June 30, 2006, there was $8.1 million of unrecognized compensation costs related to non-vested CEI restricted stock and CEI's stock options. The cost is expected to be recognized over a weighted average period of 2.1 years.

Pro Forma for 2005:

Had compensation cost for the Partnership been determined based on the fair value at the grant date for awards in accordance with SFAS No. 123, *Accounting for Stock-based Compensation*, the Partnership's net income would have been as follows (in thousands, except per unit amounts):

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

(c) Earnings per Unit and Dilution Computations

Basic earnings per unit was computed by dividing net income by the weighted average number of limited partner units outstanding for the three and six months ended June 30, 2006 and 2005. The computation of diluted earnings per unit further assumes the dilutive effect of unit options, restricted units and senior subordinated units.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and six months ended June 30, 2006 and 2005 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Basic earnings per unit:				
Weighted average limited partner units outstanding	26,572	18,124	26,064	18,111
Diluted earnings per unit:				
Weighted average limited partner units outstanding	26,572	18,124	26,064	18,111
Dilutive effect of restricted units issued	—	105	—	102
Dilutive effect of senior subordinated units	—	100	—	50
Dilutive effect of exercise of options outstanding	—	551	—	556
Diluted units	26,572	18,880	26,064	18,819

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding for the period presented. All common equivalents were antidilutive in the three and six months ended June 30, 2006 because the limited partners were allocated a net loss in the periods.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note (4). In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to CEI stock options and restricted stock all to the general partner to match the related general partner contribution for such items. Therefore, beginning in the second quarter of 2005, the general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units, and the common units. The net income allocated to the general partner for incentive distributions was $5.0 million and $2.2 million for the three months ended June 30, 2006 and 2005, respectively, and $9.7 million and $4.2 million for the six months ended June 30, 2006 and 2005, respectively. Stock-based compensation related to CEI options and restricted stock was $1.0 million and $1.0 million for the three months ended June 30, 2006 and 2005, respectively, and $1.5 million and $1.0 million for the six months ended June 30, 2006 and 2005, respectively.

(d) Income Taxes

The Partnership recorded an increase of $0.2 million to the deferred tax liability related to the effect of tax law changes enacted by the State of Texas on May 18, 2006.

(2) Significant Acquisition

On June 29, 2006, the Partnership acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale (the "Midstream Assets") from Chief Holdings LLC ("Chief") for a purchase price of approximately $475.4 million (the "Chief Acquisition"). The Midstream Assets include five gathering systems, located in parts of Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties in Texas. The Midstream Assets also include a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. The gas gathering systems consist 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 currently have the capacity to deliver approximately 250,000 MMBtu per day, and the Partnership will expand the capacity as needed to gather the volumes produced as new pipelines are constructed.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

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 market-based gathering fees 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	$	475,333
Direct acquisition costs		75
Total purchase price	$	475,408
Assets acquired:		
Current assets		26,935
Property, plant and equipment		88,075
Intangible assets		415,053
Liabilities assumed:		
Current liabilities		(54,655)
Total purchase price	$	475,408

Intangibles relate to customer relationships, including the agreement with Devon, and are being amortized over 15 years. 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 our bank credit facility, net proceeds of approximately $368.4 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 Crosstex Energy, Inc., and $6.0 million of cash.

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

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

	Pro Forma Six Months Ended June 30, 2005
Revenue	$ 1,358,337
Pro forma net income	9,000
Pro forma net income per common unit:	
Basic	$ 0.17
Diluted	$ 0.17

We have utilized the purchase method of accounting for this acquisition with an acquisition date of November 1, 2005.

(3) Long-Term Debt

As of June 30, 2006 and December 31, 2005, long-term debt consisted of the following (in thousands):

	June 30, 2006	December 31, 2005
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at June 30, 2006 and December 31, 2005 were 7.18% and 6.69%, respectively	$ 560,001	$ 322,000
Senior secured notes, weighted average interest rates at June 30, 2006 and December 31, 2005 of 6.57% and 6.64%, respectively	258,236	200,000
Note payable to Florida Gas Transmission Company	600	650
	818,837	522,650
Less current portion	(10,012)	(6,521)
Debt classified as long-term	$ 808,825	$ 516,129

On June 29, 2006, we amended our bank credit facility, increasing availability under the facility to $1 billion, with an option to increase the aggregate commitment to $1.3 billion pursuant to an accordion provision. The maturity date was extended from November 2010 to June 2011.

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

- an initial ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of 5.25 to 1.0, pro forma for any asset acquisitions. The maximum leverage ratio is reduced to 4.75 to 1 beginning July 1, 2007 and further reduces to 4.25 to 1 on January 1, 2008. The maximum leverage ratio increases to 5.25 to 1 during an acquisition adjustment period, as defined in the credit agreement; and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis, equal to 3.0 to 1.0.

On July 26, 2006, we issued $245.0 million of additional notes under the shelf agreement, increasing the amounts outstanding to $502.6 million. Proceeds were used to pay bank indebtedness.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

We were in compliance with all debt covenants at June 30, 2006 and expect to be in compliance for the next twelve months.

Additionally, the credit agreement was amended to allow for borrowings under our senior secured note shelf agreement to increase from $260 million to $510 million. See Note (9) Subsequent Event regarding new borrowings under senior secured notes in July 2006.

(4) Partners' Capital

Issuance of Units

On June 29, 2006, the Partnership issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests of the Partnership in a private equity offering for net proceeds of approximately $359.4 million. The senior subordinated series C units were issued at $28.06, which represents a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units issued at that price. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million which represents a 2% general partner interest on the market value of the private equity offering.

The senior subordinated series C units will automatically convert into common units representing limited partner interests of the Partnership on the first date on or after February 16, 2008 that conversion is permitted by our partnership agreement at a ratio of one common unit for each senior subordinated series C unit. Our partnership agreement will permit the conversion of the senior subordinated series C 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 February 16, 2008, 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 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 C units are not entitled to distributions of available cash from the Partnership until February 16, 2008.

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

Cash Distributions

In accordance with the partnership agreement, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions will generally be made 98% to the common and subordinated unitholders (other than the senior subordinated series C unitholders) and 2% to the general partner, subject to the payment of incentive distributions to the extent that certain target levels of cash distributions are achieved. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $5.0 million and $2.2 million were earned by our general partner for the three months ended June 30, 2006 and June 30, 2005, respectively. Incentive distributions totaling $9.7 million and $4.2 million were earned in the six-month period ending June 30, 2006 and June 30, 2005, respectively. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The Partnership has declared a second quarter 2006 distribution of $0.54 per unit to be paid on August 15, 2006 to unitholders of record as of August 2, 2006.

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Notes to Condensed Consolidated Financial Statements — (Continued)

(5) Derivatives

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

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Change in fair value of derivatives that do not qualify for hedge accounting	$ 3,759	$ (146)	$ 1,675	$ 530
Ineffective portion of derivatives qualifying for hedge accounting	166	80	91	(123)
	$ 3,925	$ (66)	$ 1,766	$ 407

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

	June 30, 2006	December 31, 2005
Fair value of derivative assets — current	$ 20,967	$ 12,205
Fair value of derivative assets — long term	3,850	7,633
Fair value of derivative liabilities — current	(18,816)	(14,782)
Fair value of derivative liabilities — long term	(3,341)	(3,577)
Net fair value of derivatives	$ 2,660	$ 1,479

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Notes to Condensed Consolidated Financial Statements — (Continued)

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at June 30, 2006 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than March 2008 for derivatives, excluding third-party on-system financial swaps, and extend to October 2009 for third-party on-system financial swaps. The Partnership's counterparties to hedging contracts include BP Corporation, Total Gas & Power, Cinergy, 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.

	June 30, 2006			
Transaction Type	**Total Volume**	**Pricing Terms**	**Remaining Term of Contracts**	**Fair Value** (In thousands)
Cash Flow Hedges:				
Natural gas swaps	(4,110,000)	NYME less a basis of $0.1 to NYMEX flat or fixed prices ranging from $8.20 to $10.57 settling against various Inside FERC Index prices	July 2006 — March 2008	$ 5,173
Total natural gas swaps designated as cash flow hedges				$ 5,173
Liquids swaps	(35,992,232)	Fixed prices ranging from $0.61 to $1.525 settling against Mt. Belvieu Average of daily postings (non-TET)	July 2006 — March 2008	$ (4,270)
Total liquids swaps designated as cash flow hedges				$ (4,270)
Mark to Market Derivatives:				
Swing swaps	202,399	Prices ranging from Inside FERC Index to Inside FERC	July 2006	$ (1)
Swing swaps	(2,609,797)	Index less $0.025 settling against various Gas Daily Index prices	July 2006	28
Total swing swaps				$ 27
Physical offset to swing swap transactions	2,609,797	Prices of various Inside FERC Index prices settling against	July 2006	—
Physical offset to swing swap transactions	(202,399)	various Gas Daily Index prices	July 2006	—
Total physical offset to swing swaps				$ —
Basis swaps	29,914,708	Prices ranging from Inside FERC Index less $0.39 to	July 2006 — March 2008	$ (475)
Basis swaps	(29,798,208)	Inside FERC Index plus $0.18 settling against various Inside FERC Index prices.	July 2006 — March 2008	(159)
Total basis swaps				$ (634)
Physical offset to basis swap transactions	2,871,208	Prices ranging from Inside FERC Index less $0.20 to	July 2006 — October 2006	$ 6
Physical offset to basis swap transactions	(3,537,708)	Inside FERC Index plus $0.03 settling against various Inside FERC Index prices	July 2006 — October 2006	146
Total physical offset to basis swap transactions				$ 152
Third party on-system financial swaps	10,382,100	Fixed prices ranging from $5.659 to $11.91 settling against various Inside FERC Index prices	July 2006 — October 2009	$ (10,308)
Total third party on-system financial swaps				$ (10,308)

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Notes to Condensed Consolidated Financial Statements — (Continued)

	June 30, 2006			
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value
				(In thousands)
Physical offset to third party on-system transactions	(10,382,100)	Fixed prices ranging from $5.71 to $11.96 settling against various Inside FERC Index prices	July 2006 — October 2009	11,246
Total physical offset to third party on-system swaps				$ 11,246
Storage swap transactions:				
Storage swap transactions	(355,000)	Fixed prices of $10.065 settling against various Inside FERC Index prices	February 2007	$ (139)
Total financial storage swap transactions				$ (139)
Natural gas liquid puts:				
Liquid put options (purchased)	121,077,558	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu Average Daily Index	July 2006 — December 2007	$ 2,684
Liquid put options (sold)	(53,179,312)		July 2006 — December 2007	(1,271)
Total natural gas liquid puts				$ 1,413

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

Impact of Cash Flow Hedges

Natural Gas

In the six months ended June 30, 2006, net gains on futures and basis swap hedge contracts increased gas revenue by $0.4 million. For the six months ended June 30, 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $0.3 million. In the three months ended June 30, 2006, net gains on futures and basis swap hedge contracts increased gas revenue by $0.9 million. For the three months ended June 30, 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $0.3 million. As of June 30, 2006, an unrealized derivative fair value gain of $5.3 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). As of June 30, 2006, $4.9 million of the fair value gain is expected to be reclassified into earnings through June 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

The settlement of futures contracts and basis swap agreements related to July 2006 gas production reduced gas revenue by approximately $1.0 million.

Liquids

For the six months ended June 30, 2006, net gains on liquids swap hedge contracts increased liquids revenue by approximately $1.1 million. For the three months ending June 0, 2006, net losses on liquids swap hedge contracts decreased liquids revenue by less than $0.1 million. As of June 30, 2006, an unrealized derivative fair value loss of $4.2 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). As of June 30, 2006, $3.2 million of the fair value loss is expected to be reclassified into earnings through June 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

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Notes to Condensed Consolidated Financial Statements — (Continued)

Derivatives Other than Cash Flow Hedges

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

	Maturity Periods			
	Less Than One Year	One to Two Years	More Than 2 Years	Total Fair Value
June 30, 2006	$ 554	$ 1,148	$ 55	$ 1,757

(6) Transactions with Related Parties

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden) and treats gas for Erskine Energy Corporation (Erskine) and Approach Resources, Inc. (Approach). All three entities are affiliates of the Partnership by way of equity investments made by Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P., collectively a major shareholder in CEI. During the three months ended June 30, 2006 and 2005, the Partnership purchased natural gas from Camden in the amount of approximately $7.8 million and $11.5 million, respectively, and received approximately $0.7 million and $0.6 million in treating fees from Camden. During the three months ended June 30, 2006 the Partnership received $0.3 million and $0.1 million from Erskine and Approach respectively. The Partnership purchased natural gas from Camden in the amount of approximately $18.7 million and $20.7 million for the six months ended June 30, 2006 and 2005, respectively, and received approximately $1.4 million and $1.3 million, respectively, in treating fees from Camden. For the six months ended June 30, 2006 the Partnership received treating fees of $0.7 million and $0.2 million from Erskine and Approach respectively.

Purchase of Senior Subordinated Series C Units by Related Parties

On June 29, 2006, CEI purchased $180.0 million and Lubar Equity Fund, LLC purchased $8.0 million of our senior subordinated series C units issued in a private placement. The funds raised in the private offering were used to acquire the natural gas gathering pipeline systems and related facilities of Chief Holdings LLC. Mr. Sheldon B. Lubar is a member of the board of directors of the general partner of the general partner of the Partnership and is a member of CEI's board and is also an affiliate of Lubar Equity Fund, LLC.

(7) Commitments and Contingencies

(a) Employment Agreements

Each member of senior management of the Partnership is a party to an employment contract with the general partner. The employment agreements provide each member of senior management with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

(b) Environmental Issues

The Partnership acquired the south Louisiana processing assets from El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action

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Notes to Condensed Consolidated Financial Statements — (Continued)

Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects.

The estimated remediation costs are expected to be approximately $0.3 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

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

(c) Other

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

(8) Segment Information

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

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

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Notes to Condensed Consolidated Financial Statements — (Continued)

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

	Midstream	Treating	Totals
		(In thousands)	
Three months ended June 30, 2006:			
Sales to external customers	$ 727,866	$ 15,983	$ 743,849
Inter-segment sales	2,349	(2,349)	—
Interest expense, net	11,008	882	11,890
Depreciation and amortization	14,524	4,184	18,708
Segment profit	(4,394)	2,501	(1,893)
Segment assets	1,754,557	182,911	1,937,468
Capital expenditures*	30,237	6,829	37,066
Three months ended June 30, 2005:			
Sales to external customers	$ 619,432	$ 11,040	$ 630,472
Inter-segment sales	2,279	(2,279)	—
Interest expense, net	2,471	725	3,196
Depreciation and amortization	4,747	2,623	7,370
Segment profit	3,578	1,048	4,626
Segment assets	479,089	121,930	601,019
Capital expenditures*	7,585	6,158	13,743
Six months ended June 30, 2006:			
Sales to external customers	$ 1,529,996	$ 30,549	$ 1,560,545
Inter-segment sales	4,950	(4,950)	—
Interest expense, net	18,247	2,155	20,402
Depreciation and amortization	28,918	6,840	35,758
Segment profit	(3,979)	4,434	455
Segment assets	1,754,557	182,911	1,937,468
Capital expenditures*	85,615	12,351	97,966
Six months ended June 30, 2005:			
Sales to external customers	$ 1,158,996	$ 20,947	$ 1,179,943
Inter-segment sales	3,903	(3,903)	—
Interest expense, net	5,226	1,335	6,561
Depreciation and amortization	9,344	4,962	14,306
Segment profit	5,793	2,204	7,997
Segment assets	479,089	121,930	601,019
Capital expenditures*	13,014	12,766	25,780

* Excluding acquisitions

(9) Subsequent Event

On July 25, 2006, the Partnership issued $245.0 million aggregate principal amount of senior secured notes to institutional investors. The senior secured notes mature in 10 years and have an interest rate of 6.96 percent per annum. Proceeds from the notes were used to repay borrowings under the bank credit facility.

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

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

Overview

We are a Delaware limited partnership formed by Crosstex Energy, Inc. ("CEI") on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, the North Texas Barnett Shale area, Louisiana and Mississippi. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and natural gas liquids, or 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 six months ended June 30, 2006, 79% of our gross margin was generated in the Midstream division with the balance in the Treating division. We manage our business by focusing on gross margin because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas and NGLs for a fee. We buy and sell most of our gas at a fixed relationship to the relevant index price, and hedge a significant portion of the gas that is bought based on a percentage of the relevant index in order to protect our margins from 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 the liquids to protect our margins from changes in liquids prices. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

Since the formation of our predecessor, we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2000 through June 30, 2006, we have invested over $1.6 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 or 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 from NGLs 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 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 usually based on either a percentage of the liquids volume recovered or a fixed fee per unit processed. Fractionation and marketing fees are generally fixed fee per unit of products.

We generate treating revenues under three arrangements:

- a fixed fee for operating the plant for a certain period, which accounted for approximately 47% and 40% of the operating income in our Treating division for the six months ended June 30, 2006 and 2005, respectively;
- a volumetric fee based on the amount of gas treated, which accounted for approximately 37% and 51% of the operating income in our Treating division for the six months ended June 30, 2006 and 2005, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 16% and 9% of the operating income in our Treating division for the six months ended June 30, 2006 and 2005, respectively.

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

We have grown significantly through asset purchases in recent years. These acquisitions create many of the major differences when comparing operating results from one period to another. The most significant asset purchases since January 2005 were the acquisition of the Chief Holdings LLC ("Chief") natural gas pipeline systems and related facilities in the Barnett Shale in June 2006, the acquisition of Hanover Compression Company's treating assets in February 2006, the acquisition of El Paso Corporation's processing and liquids business in southern Louisiana in November 2005, the acquisition of Graco Operations' treating assets in January 2005 and the acquisition of Cardinal Gas Services' treating and dewpoint control assets in May 2005.

On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.4 million. The acquired systems consist of approximately 250 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties, all of which are located in Texas. The acquired assets also include a 125 million cubic feet per day CO_2 treating plant and compression facilities with 26,000 horsepower. At closing, approximately 160,000 net acres previously owned by Chief and acquired by Devon Energy Corporation simultaneously with our acquisition and 60,000 net acres owned by other producers were dedicated to the systems.

On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.5 million. After this acquisition we have approximately 160 treating plants in operation and a total fleet of approximately 190 units.

On November 1, 2005 we acquired El Paso Corporation's processing and liquids business in south Louisiana for $481.0 million. The assets acquired include 2.3 billion cubic feet per day of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The primary facilities and other assets we acquired consist of: (1) the Eunice processing plant and fractionation facility; (2) the Pelican processing plant; (3) the Sabine Pass processing plant; (4) a 23.85% interest in the Blue Water gas processing plant; (5) the Riverside fractionator and loading facility; (6) the Cajun Sibon pipeline; and (7) the Napoleonville natural gas liquid storage facility. In 2006 we acquired an additional 35.42% interest in the Blue Water gas processing plant for $16.3 million and became the operator of the plant.

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

Results of Operations

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

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(Dollars in millions)			
Midstream revenues	$ 727.9	$ 619.4	$ 1,530.0	$ 1,159.0
Midstream purchased gas	676.4	594.4	1,431.9	1,111.0
Profit on Energy Trading Activities	0.8	0.3	1.2	0.9
Midstream gross margin	52.3	25.3	99.3	48.9
Treating revenues	16.0	11.0	30.5	20.9
Treating purchased gas	2.1	1.7	4.5	3.2
Treating gross margin	13.9	9.3	26.0	17.7
Total gross margin	$ 66.2	$ 34.6	$ 125.3	$ 66.6
Midstream Volumes (MMBtu/d):				
Gathering and transportation	1,394,000	1,165,000	1,267,000	1,175,000
Processing	1,970,000	486,000	1,870,000	448,000
Producer services	173,000	194,000	182,000	185,000
Plants in service at end of period	160	100	160	100

Three Months Ended June 30, 2006 Compared to Three Months Ended June 30, 2005

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $52.3 million for the three months ended June 30, 2006 compared to $25.3 million for the three months ended June 30, 2005, an increase of $27.0 million, or 107%. This increase was primarily due to acquisitions, increased system throughput, and a favorable processing environment for natural gas liquids.

The south Louisiana natural gas processing and liquids business acquired from El Paso Corporation ("El Paso") in November 2005 contributed $20.5 million to Midstream gross margin in the second quarter of 2006. This amount was driven by the three largest processing plants, Eunice, Pelican and Sabine Pass, which contributed gross margin amounts of $6.7 million, $6.0 million and $2.7 million, respectively. The Riverside fractionation facility also contributed $2.9 million in gross margin to the south Louisiana operations. Operational improvements and volume increases on the Mississippi system contributed margin growth of $2.2 million. Increased processing volumes at the Gibson and Plaquemine plants, due to recent drilling successes by producers, and increased unit margins due to favorable NGLs markets accounted for $2.5 million increased gross margin. The North Texas Pipeline ("NTPL") commenced operation during the second quarter of 2006 and contributed $2.0 million in gross margin.

Treating gross margin was $13.9 million for the three months ended June 30, 2006 compared to $9.3 million in the same period in 2005, an increase of $4.6 million, or 49%. Treating plants in service increased from 100 plants in June 2005 to 160 plants in June 2006. The increase is primarily due to the acquisition of the amine treating assets from Hanover Compressor Company in February 2006. New plants in service contributed approximately $4.3 million to Treating gross margin. Growth in upstream services during the second quarter of 2006 contributed an additional $0.3 million to gross margin.

Profit on energy trading activity increased from a profit of $0.3 million for the three months ended June 30, 2005 to a profit of $0.8 million for the three months ended June 30, 2006. Energy trading activity included approximately a $0.3 million gain associated with realized energy trading swap activities. The remaining increase was due to south Louisiana margin activity.

Operating Expenses. Operating expenses were $22.8 million for the three months ended June 30, 2006 compared to $12.2 million for the three months ended June 30, 2005, an increase of $10.7 million, or 87.6%.

Midstream operating expenses increased by $7.6 million due to the acquisition of the south Louisiana assets from El Paso. The growth in treating plants in service increased operating expenses by $1.7 million. Other Midstream increases were due to the commencement of operations of the NTPL of $0.3 million and additional compressor costs on existing assets of $0.7 million. Operating expenses included $0.2 million of stock-based compensation expense for the three months ended June 30, 2005 compared to $0.3 million of stock-based compensation expense for the three months ended June 30, 2006.

General and Administrative Expenses. General and administrative expenses were $10.9 million for the three months ended June 30, 2006 compared to $7.8 million for the three months ended June 30, 2005, an increase of $3.2 million, or 40.9%. A substantial part of the increased expenses resulted primarily from staffing related costs of $2.2 million. The staff additions associated with the requirements of the El Paso and Hanover acquisitions accounted for the majority of the $2.2 million costs. General and administrative expenses included stock-based compensation expense of $1.9 million and $1.1 million for the three months ended June 30, 2006 and 2005, respectively. The $0.8 million increase in stock-based compensation, determined in accordance with SFAS No. 123R,*"Share Based Compensation"* ("FAS 123R") during 2006 and in accordance with Accounting Principles Board Options No. 25, *"Accounting for Stock Issued to Employees"* ("APB25") in 2005, primarily relates to restricted stock and unit grants.

Gain/Loss on Derivatives. We had a loss on derivatives of $3.9 million for the three months ended June 30, 2006 compared to a gain of $0.1 million for the three months ended June 30, 2005. The loss in 2006 includes a loss of $2.7 million on puts acquired in 2005 related to the acquisition of the El Paso assets, a loss of $1.4 million associated with our basis swaps, a loss of $0.1 million due to ineffectiveness and a gain of $0.3 million associated with derivatives for third-party on-system financial transactions and storage financial transactions (including $0.1 million of realized gains). As of June 30, 2006, the fair value of the puts was $1.4 million.

Depreciation and Amortization. Depreciation and amortization expenses were $18.7 million for the three months ended June 30, 2006 compared to $7.4 million for the three months ended June 30, 2005, an increase of $11.3 million, or 153.8%. Midstream depreciation and amortization increased $8.5 million due to the acquisition of the south Louisiana assets and intangibles and $0.9 million due to the NTPL which was placed in service April 2006. New treating plants placed in service and assets acquired from Hanover resulted in an increase of $1.3 million of depreciation and amortization expenses. The remaining $0.6 million increase in depreciation and amortization expenses is a result of expansion projects, including our office expansions and other new assets.

Interest Expense. Interest expense was $11.9 million for the three months ended June 30, 2006 compared to $3.2 million for the three months ended June 30, 2005, an increase of $8.7 million, or 272.0%. The increase relates primarily to an increase in debt outstanding and higher interest rates between the three-month periods (weighted average rate of 6.8% in 2006 compared to 6.0% in 2005).

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $99.3 million for the six months ended June 30, 2006 compared to $48.9 million for the six months ended June 30, 2005, an increase of $50.4 million, or 103%. This increase was primarily due to acquisitions, increased system throughput, and a favorable processing environment for NGLs.

The south Louisiana natural gas processing and liquids business acquired from El Paso in November 2005 contributed $39.1 million to Midstream gross margin in the first half of 2006. This amount was driven by the three largest processing plants, Eunice, Pelican and Sabine Pass, which contributed gross margin amounts of $17.1 million, $9.4 million and $6.4 million, respectively. The Riverside fractionation facility also contributed $3.2 million in gross margin to the south Louisiana operations. Operational improvements and volume increases on the Mississippi and LIG systems contributed margin growth of $4.8 million and $2.7 million, respectively. Increased processing volumes at the Gibson and Plaquemine plants, due to recent drilling successes by producers, and increased unit margins due to favorable NGLs markets accounted for $4.5 million of increased gross margin. The NTPL commenced operation during the second quarter of 2006 and contributed $2.0 million in gross margin. These gains were partially offset by a margin decline of $2.3 million on the Gregory system in South Texas due to lower throughput volumes.

Treating gross margin was $26.0 million for the six months ended June 30, 2006 compared to $17.7 million in the same period in 2005, an increase of $8.3 million, or 47%. Treating plants in service increased from 100 plants in June 2005 to 160 plants in June 2006. The increase is primarily due to the acquisition of the amine treating assets from Hanover Compressor Company in February 2006. New plants in service contributed approximately $7.2 million to Treating gross margin. Growth in upstream services during the first half of 2006 contributed an additional $0.4 million to gross margin. Existing plant assets contributed $0.7 million in gross margin growth primarily due to plant expansion projects and increased volumes.

The profit on energy trading activities was $1.2 million for the six months ended June 30, 2006 compared to $0.9 million for the six months ended June 30, 2005, an increase of $0.3 million. The increase primarily relates to energy trading activity on the south Louisiana assets.

Operating Expenses. Operating expenses were $44.8 million for the six months ended June 30, 2006 compared to $23.7 million for the six months ended June 30, 2005, an increase of $21.1 million, or 88.9%. An increase of $15.2 million of operating expenses was associated with the acquisition of the south Louisiana assets. The growth in the number of treating plants in service increased operating expenses by $3.0 million. Other Midstream increases were due to additional compressor costs on existing assets of $1.3 million and the commencement of operations of the NTPL of $0.3 million. General operations expenses (expenses not directly related to specific assets) exceeded the June 2005 comparative period by $1.2 million. Operating expenses included $0.5 million of stock-based compensation expense for the six months ended June 30, 2006 compared to $0.2 million of stock-based compensation expense for the six months ended June 30, 2005.

General and Administrative Expenses. General and administrative expenses were $22.3 million for the six months ended June 30, 2006 compared to $14.2 million for the six months ended June 30, 2005, an increase of $8.1 million, or 56.7%. A substantial part of the increased expenses resulted from increased staffing related costs of $5.1 million. The staff additions associated with the requirements of the El Paso and Hanover acquisitions accounted for the majority of the $5.1 million in increased costs. General and administrative expenses included stock-based compensation expense of $3.4 million and $1.3 million for the six months ended June 30, 2006 and 2005, respectively. The $2.1 million increase in stock-based compensation, determined in accordance with FAS 123R during 2006 and in accordance with APB25 in 2005, primarily relates to restricted stock and unit grants. Other expenses, including audit, legal and other consulting fees, office rent, travel and training accounted for $1.0 million of the increase.

Gain/Loss on Derivatives. We had a loss on derivatives of $1.8 million for the six months ended June 30, 2006 compared to a loss of $0.4 million for the six months ended June 30, 2005. The loss in 2006 includes a loss of $3.8 million on puts acquired in 2005 related to the acquisition of the El Paso assets and a loss of $0.5 million associated with our basis swaps offset by a gain of $2.5 million associated with derivatives for third-party on-system financial transactions and storage financial transactions (including $1.3 million of realized gains). As of June 30, 2006, the fair value of the puts was $1.4 million.

Depreciation and Amortization. Depreciation and amortization expenses were $35.8 million for the six months ended June 30, 2006 compared to $14.3 million for the six months ended June 30, 2005, an increase of $21.5 million, or 150.0%. The increase in depreciation and amortization expenses related to the south Louisiana assets and intangibles was $16.8 million. The new plants acquired from Hanover, together with new treating plants placed in service, resulted in an increase of $2.5 million. The remaining $2.2 million increase in depreciation and amortization expenses is a result of expansion projects, including our office expansions and other new assets including the NTPL.

Interest Expense. Interest expense was $20.4 million for the six months ended June 30, 2006 compared to $6.6 million for the six months ended June 30, 2005, an increase of $13.8 million. The increase relates primarily to an increase in debt outstanding and higher interest rates between six-month periods (weighted average rate of 6.7% in 2006 compared to 6.2% in 2005).

Critical Accounting Policies

Information regarding the Partnership's Critical Accounting Policies is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2005.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $37.7 million for the six months ended June 30, 2006 compared to $15.3 million for the six months ended June 30, 2005. Income before non-cash income and expenses was $44.5 million in 2006 and $24.5 million in 2005. Changes in working capital provided $6.8 million in cash flows from operating activities in 2006 as compared to $9.2 million in cash flows used by working capital changes in 2005.

Net cash used in investing activities was $650.4 million and $41.4 million for the six months ended June 30, 2006 and 2005, respectively. Net cash used in investing activities during 2006 related to the $475.4 million acquisition of assets from Chief, the $51.5 million acquisition of Hanover's treating assets, and a $16.3 million acquisition of an additional interest in the Blue Water processing plant. The connection of new wells to various systems, pipeline integrity projects, pipeline relocations and various other internal growth projects totaled $97.9 million for the first half of 2006, including $36.4 million related to the new NTPL project and $23.8 million for the Parker County gathering project.

Net cash provided by financing activities was $612.3 million for the six months ended June 30, 2006 compared to $22.7 million provided by financing activities for the six months ended June 30, 2005. Net cash provided by financing activities included $368.4 million from the issuance of senior subordinated series C units, including the general partner contribution, net borrowings under the amended credit facility of $238.0 million and net borrowings under our senior secured notes of $58.2 million. Distributions to partners totaled $36.2 million in the first half of 2006 compared to distributions in the first half of 2005 of $20.7 million. Drafts payable decreased by $14.1 million requiring the use of cash in the six months ended June 30, 2006 as compared to a decrease in drafts payable of $12.7 million for the six months ended June 30, 2005. 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 $19.6 million as of June 30, 2006, primarily due to accounts payable of $36.5 million recorded as a result of the Chief Acquisition and drafts payable of $15.8 million. As discussed under "Cash Flows" above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank. We borrow money under our bank credit facility to fund checks as they are presented. As of June 30, 2006, we had $380.1 million of available borrowings under this facility.

Issuance of Senior Subordinated Series C Units. On June 29, 2006, we issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests in a private equity offering for net proceeds of $360.0 million. The senior subordinated series C units were issued at a purchase price of $28.06 per unit, which represents a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units issued at that price. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million in connection with this issuance which represents a 2% general partner contribution on the market value of the issued units.

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

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

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

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.54 per quarter and to fund a portion of our anticipated capital expenditures through June 30, 2007. Total capital expenditures are budgeted to be approximately $82.0 million for the remainder of 2006. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of June 30, 2006.

Indebtedness

As of June 30, 2006 and December 31, 2005, long-term debt consisted of the following (in thousands):

	June 30, 2006	December 31, 2005
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at June 30, 2006 and December 31, 2005 were 7.18% and 6.69%, respectively	$ 560,001	$ 322,000
Senior secured notes, weighted average interest rates at June 30, 2006 and December 31, 2005 of 6.57% and 6.64%, respectively	258,236	200,000
Note payable to Florida Gas Transmission Company	600	650
	818,837	522,650
Less current portion	(10,012)	(6,521)
Debt classified as long-term	$ 808,825	$ 516,129

On June 29, 2006, we amended our bank credit facility, increasing availability under the facility to $1 billion, with an option to increase the aggregate commitment to $1.3 billion pursuant to an accordion provision. The maturity date was extended from November 2010 to June 2011.

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

- an initial ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of 5.25 to 1.0, pro forma for any asset acquisitions. The maximum leverage ratio is reduced to 4.75 to 1 beginning July 1, 2007 and further reduces to 4.25 to 1 on January 1, 2008. The maximum leverage ratio increases to 5.25 to 1 during an acquisition adjustment period, as defined in the credit agreement; and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis, equal to 3.0 to 1.0.

Additionally, the credit agreement was amended to allow for borrowings under our senior secured note shelf agreement to increase from $260 million to $510 million.

On July 26, 2006, we added $245.0 million of additional notes under the shelf agreement, increasing the amounts outstanding to $502.6 million. Proceeds were used to pay bank indebtedness.

We were in compliance with all debt covenants at June 30, 2006 and expect to be in compliance for the next twelve months.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2006, is as follows:

	Payments Due by Period						
	Total	2006	2007	2008	2009	2010	Thereafter
				(In millions)			
Long-Term Debt	$ 808.8	$ 10.0	$ 9.4	$ 9.4	$ 20.3	$ 32.0	$ 727.7
Capital Lease Obligations	—	—	—	—	—	—	—
Operating Leases	93.6	7.9	15.6	15.3	14.9	14.7	25.2
Unconditional Purchase Obligations	14.7	14.7	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—	—
Total Contractual Obligations	$ 917.1	$ 32.6	$ 25.0	$ 24.7	$ 35.2	$ 46.7	$ 752.9

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

The unconditional purchase obligations for 2006 primarily relate to the purchase of pipe for the construction of the North Louisiana Pipeline extension.

Recently issued Accounting Standard

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” and must be adopted by the Partnership no later than January 1, 2007. 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 is a pass thru entity and does not expect a major impact on financial statement presentation as a result of FIN 48.

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. Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “forecast,” “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. In addition to specific uncertainties discussed elsewhere in this Form 10-Q, the 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, 2005, and those set forth in Part III, “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. We face market risk from commodity price variations, primarily due to fluctuations in the price of a portion of the natural gas we purchase and for NGLs we receive as fees. For the portion of the natural gas we process and for which we have taken the processing risk, we are at risk for the difference in the value of the NGL products we produce versus the value of the gas used in fuel and shrinkage in their production. We also incur credit risks and risks related to interest rate variations.

Commodity Price Risk. Approximately 6.8% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our resale margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. We have hedged approximately 67% of our exposure to gas price fluctuations through December 2006, approximately 54% of our exposure to gas price fluctuations for the year ending December 2007, and approximately 15% of our exposure to gas price fluctuations for the first quarter of 2008. We also have hedges in place covering at least 100% of the minimum liquid volumes we expect to receive through the end of 2007 and approximately 20% for the first quarter of 2008 at our south Louisiana assets; and 78% of the liquids at our other assets in 2006, 60% in 2007, and 20% 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 on the same basis. However, it is normal to experience fluctuations in the volumes of gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

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

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

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

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

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

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

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

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

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period is reported as profit or loss on energy trading contracts in the statement of operations. In addition, realized gains and losses from settled contracts accounted for as cash flow hedges are also recorded in profit or loss on energy trading contracts. As of June 30, 2006, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments had a net fair asset value of $1.3 million, excluding the fair value asset of $1.4 million associated with the NGL puts. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $8.3 million in the net fair value to a net liability of these contracts as of June 30, 2006 of $7.0 million. The value of the natural gas puts would also decrease as a result of an increase in NGL prices, but we are unable to determine the impact of a 10% price change. Our maximum loss on these puts is the remaining $1.4 million fair value of the puts.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our long-term debt with floating interest rates. At June 30, 2006, we had $560.0 million of indebtedness outstanding under floating rate debt. The impact of a 1% increase in interest rates on our expected debt would result in an increase in interest expense and a decrease in income before taxes of approximately $5.6 million per year. This amount has been determined by considering the impact of such hypothetical interest rate increase on our non-hedged, floating rate debt outstanding at June 30, 2006.

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

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

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

Item 4. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2006 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal controls over financial reporting that occurred in the three months ended June 30, 2006 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART II — OTHER INFORMATION

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

Other than risk factor presented below, there have been no material changes from the risk factors disclosed under the heading "Risk Factors" in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2005 (the "Annual Report"). The risk factor below updates, and should be read in conjunction with, the risk factors disclosed in our Annual Report and in our other filings with the SEC.

If our assumptions used in making the acquisition of the Barnett Shale systems and facilities from Chief Holdings LLC are inaccurate, our future financial performance may be limited.

We acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale, which we refer to as the Midstream Assets, from Chief Holdings LLC in June 2006. This acquisition was made based on our understanding of future drilling plans by Devon Energy Corporation, which acquired Chief's producing assets and acreage previously owned by Chief that is dedicated to the Midstream Assets. In addition, we assumed in our analysis the continued drilling success by other producers that own acreage dedicated to the Midstream Assets, production success on acreage not dedicated to the system and that we will be able to tie a certain portion of that new production into the system. Production currently flowing through the system is very small relative to the quantities we have assumed will be developed in the next few years. If our assumptions are inaccurate, the drilling plans of the producers are delayed, the producers are not successful in completing their wells or we are not successful in our commercial efforts to tie in gas from undedicated acreage, then our anticipated results from the acquisition of the Midstream Assets could be significantly negatively impacted. In addition, the failure to successfully integrate the Midstream Assets with our existing business and operations in a timely manner may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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	—	Fifth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of June 29, 2006 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).

Number		Description
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	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
10.2	—	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, 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 June 29, 2006, filed with the Commission on July 6, 2006).
10.3	—	Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.4	—	Senior Subordinated Series C Unit Purchase Agreement, dated as of May 16, 2006, 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 May 16, 2006, filed with the Commission on May 17, 2006).
10.5	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LBI Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
31.1*	—	Certification of the principal executive officer.
31.2*	—	Certification of the principal financial officer.
32.1*	—	Certification of the principal executive officer and principal financial officer of the Partnership 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 August, 2006.

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ William W. Davis
William W. Davis
Executive Vice President and
Chief Financial Officer

EXHIBIT INDEX

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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 Partnership pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

Exhibit 31.1

CERTIFICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

/s/ BARRY E. DAVIS

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

Date: August 9, 2006

Exhibit 31.2

CERTIFICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

/s/ WILLIAM W. DAVIS

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

Date: August 9, 2006

Exhibit 32.1

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

In connection with the Quarterly Report of Crosstex Energy, L.P. (the “Registrant”) on Form 10-Q for the quarter ended June 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

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

August 9, 2006

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

August 9, 2006

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