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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

☒ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

for the quarterly period ended March 31, 2012

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of April 24, 2012, the Registrant had 50,869,997 common units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	March 31, 2012 (Unaudited)	December 31, 2011
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,630	$ 24,143
Accounts receivable:		
Trade, net of allowance for bad debt of $210 and $405, respectively	12,352	22,680
Accrued revenue and other	118,623	143,115
Fair value of derivative assets	1,274	2,867
Natural gas and natural gas liquids, prepaid expenses and other	16,338	9,951
Total current assets	169,217	202,756
Property and equipment, net of accumulated depreciation of $425,708 and $406,273, respectively	1,251,304	1,241,901
Fair value of derivative assets	131	—
Intangible assets, net of accumulated amortization of $211,975 and $199,248, respectively	438,734	451,462
Investment in limited liability company	39,860	35,000
Other assets, net	24,204	24,212
Total assets	$ 1,923,450	$ 1,955,331
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and other	$ 16,389	$ 22,550
Accrued gas purchases	80,203	106,232
Fair value of derivative liabilities	4,843	5,587
Other current liabilities	46,828	66,065
Accrued interest	8,991	24,918
Total current liabilities	157,254	225,352
Long-term debt	852,883	798,409
Other long-term liabilities	23,156	23,919
Deferred tax liability	7,067	7,192
Fair value of derivative liabilities	110	—
Commitments and contingencies	—	—
Partners' equity	882,980	900,459
Total liabilities and partners' equity	$ 1,923,450	$ 1,955,331

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Statements of Operations

	Three Months Ended March 31, 2012	2011
	(Unaudited) (In thousands, except per unit amounts)	
Revenues	$ 371,709	$ 489,770
Operating costs and expenses:		
Purchased gas and NGLs	271,956	399,933
Operating expenses	27,806	25,044
General and administrative	14,963	11,755
Gain on sale of property	(98)	(19)
Loss on derivatives	2,169	3,421
Depreciation and amortization	32,178	29,653
Total operating costs and expenses	348,974	469,787
Operating income	22,735	19,983
Other income (expense):		
Interest expense, net of interest income	(19,382)	(19,769)
Other income	12	113
Total other expense	(19,370)	(19,656)
Income before non-controlling interest and income taxes	3,365	327
Income tax provision	(424)	(253)
Net income	2,941	74
Less: Net loss attributable to the non-controlling interest	(38)	(54)
Net income attributable to Crosstex Energy, L.P.	$ 2,979	$ 128
Preferred interest in net income attributable to Crosstex Energy, L.P.	$ 4,853	$ 4,265
General partner interest in net income	$ (71)	$ (522)

Limited partners' interest in net income attributable to Crosstex Energy, L.P.	$ (1,803)	$ (3,615)
Net loss attributable to Crosstex Energy, L.P. per limited partners' unit:		
Basic and diluted common unit	$ (0.03)	$ (0.07)

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income (Loss)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(Unaudited) (In thousands)	
Net income	$ 2,941	$ 74
Hedging losses reclassified to earnings	354	388
Adjustment in fair value of derivatives	(39)	(1,397)
Comprehensive income (loss)	3,256	(935)
Comprehensive loss attributable to non-controlling interest	38	54
Comprehensive income (loss) attributable to Crosstex Energy, L.P.	$ 3,294	$ (881)

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Three Months Ended March 31, 2012

	Common Units $	Common Units Units	Preferred Units $	Preferred Units Units	General Partner Interest $	General Partner Interest Units	Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total
					(Unaudited) (In thousands)				
Balance, December 31, 2011	$ 730,010	50,677	$ 147,770	14,706	$ 20,322	1,334	$ (503)	$ 2,860	$ 900,459
Proceeds from exercise of unit options	178	35	—	—	—	—	—	—	178
Conversion of restricted units for common units, net of units withheld for taxes	(980)	156	—	—	—	—	—	—	(980)
Capital contributions	—	—	—	—	80	4	—	—	80
Stock-based compensation	1,338	—	—	—	1,160	—	—	—	2,498
Distributions	(16,584)	—	(4,706)	—	(1,221)	—	—	—	(22,511)
Net income (loss)	(1,803)	—	4,853	—	(71)	—	—	(38)	2,941
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	354	—	354
Adjustment in fair value of derivatives	—	—	—	—	—	—	(39)	—	(39)
Balance, March 31, 2012	$ 712,159	50,868	$ 147,917	14,706	$ 20,270	1,338	$ (188)	$ 2,822	$ 882,980

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income	$ 2,941	$ 74
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	32,178	29,653
Gain on sale of property	(98)	(19)
Deferred tax benefit	(125)	(125)
Non-cash stock-based compensation	2,498	2,190
Non-cash portion of derivatives loss	1,143	1,574
Amortization of debt issue costs	1,247	1,552
Amortization of discount on notes	474	474
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	34,821	2,793
Natural gas and natural gas liquids, prepaid expenses and other	(5,817)	(1,547)

Accounts payable, accrued gas purchases and other accrued liabilities	(57,881)	(34,799)
Net cash provided by operating activities	11,381	1,820
Cash flows from investing activities:		
Additions to property and equipment	(36,269)	(21,596)
Proceeds from sale of property	121	47
Investment in limited liability company	(4,860)	—
Net cash used in investing activities	(41,008)	(21,549)
Cash flows from financing activities:		
Proceeds from borrowings	169,000	84,250
Payments on borrowings	(115,000)	(68,250)
Payments on capital lease obligations	(762)	(723)
Increase (decrease) in drafts payable	(2,651)	6,302
Debt refinancing costs	(1,240)	(106)
Conversion of restricted units, net of units withheld for taxes	(980)	(1,328)
Distribution to partners	(22,511)	(17,597)
Proceeds from exercise of unit options	178	224
Contributions from general partner	80	97
Net cash provided by financing activities	26,114	2,869
Net decrease in cash and cash equivalents	(3,513)	(16,860)
Cash and cash equivalents, beginning of period	24,143	17,697
Cash and cash equivalents, end of period	$ 20,630	$ 837
Cash paid for interest	$ 34,183	$ 33,693
Cash paid for income taxes	$ —	$ —

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

March 31, 2012
(Unaudited)

(1) General

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

Crosstex Energy, L.P., a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, processing and marketing of natural gas, natural gas liquids, or NGLs, and providing terminal services for crude oil. The Partnership connects the wells of natural gas producers in the geographic areas of its gathering systems in order to gather for a fee or purchase the gas production, processes natural gas for the removal of NGLs, transports natural gas and NGLs and ultimately provides natural gas and NGLs to a variety of markets. The Partnership operates processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee arrangements. In addition, the Partnership purchases natural gas and NGLs from producers not connected to its gathering systems for resale and markets natural gas and NGLs on behalf of producers for a fee. The Partnership recently added crude oil terminal facilities in south Louisiana to provide access for crude oil producers to the premium markets in this area.

Crosstex Energy GP, LLC is the general partner of the Partnership. Crosstex Energy GP, LLC is a direct, wholly-owned subsidiary of Crosstex Energy, Inc. (CEI).

(a) Basis of Presentation

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. Certain reclassifications have been made to the consolidated financial statements for the prior year to conform to the current presentation. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership's annual report on Form 10-K for the year ended December 31, 2011.

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) Investment in Limited Liability Company

On June 22, 2011, the Partnership entered into a limited liability agreement with Howard Energy Partners ("HEP") for an initial capital contribution of $35.0 million in exchange for an individual ownership interest in HEP of approximately 35.0 percent. In addition to the Partnership's contribution, an unrelated party also provided a capital contribution of $35.0 million for a 35.0 percent ownership interest in HEP with HEP management and a few private investors owning the remaining 30.0 percent interest. HEP owns midstream assets and provides midstream and construction services to Eagle Ford Shale producers. This investment in HEP is accounted for under the equity method of accounting and is reflected on the balance sheet as "Investment in limited liability company." On March 13, 2012, the Partnership made a $4.9 million capital contribution to HEP related to HEP's announced definitive agreement to acquire substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas as described in Note (10) to the condensed consolidated financial statements.

(c) Potential Changes in use of Sabine Plant during 2012.

Currently, the Partnership's Sabine plant has a contract with a third-party to fractionate the raw-make NGLs produced by the plant. This contract, which was scheduled to expire on March 1, 2012, was extended through June 30, 2012 and may be extended on a month-to-month basis thereafter. The Partnership will negotiate with this third-party to establish a long-term fractionation agreement. If this third-party ceases to fractionate the produced NGLs from the Sabine plant after June 30, 2012 and the partnership is unsuccessful in determining another alternative for our Sabine customers, the partnership will cease operation of the Sabine plant. Although the partnership does not have specific plans at this time to relocate the Sabine plant if it is idled, the partnership may utilize it elsewhere in its operations. The net book value of the Sabine plant was

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$47.4 million (including $13.7 million of intangible assets attributable to customer relationships) as of March 31, 2012. If the plant is idled on a long-term basis, an impairment may be recorded to expense the non-recoverable costs associated with the plant's current location, which are estimated to be less than $28.0 million based on the net book value as of March 31, 2012.

(2) Long-Term Debt

As of March 31, 2012 and December 31, 2011, long-term debt consisted of the following (in thousands):

	March 31, 2012	December 31, 2011
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at March 31, 2012 and December 31, 2011 was 3.16% and 2.9%, respectively	$ 139,000	$ 85,000
Senior unsecured notes (due 2018), net of discount of $11.1 million and $11.6 million, respectively, which bear interest at the rate of 8.875%	713,883	713,409
Debt classified as long-term	$ 852,883	$ 798,409

Credit Facility. As of March 31, 2012, there was $59.8 million in outstanding letters of credit and $139.0 million borrowed under the Partnership's bank credit facility, leaving approximately $436.2 million available for future borrowing based on the borrowing capacity of $635.0 million. On January 24, 2012, the Partnership amended its credit facility. This amendment increased its borrowing capacity from $485.0 million to $635.0 million and amended certain terms under the facility to provide additional financial flexibility during the remaining four-year term of the facility. The credit facility is guaranteed by substantially all of the Partnership's subsidiaries and is secured by first priority liens on substantially all of the Partnership's assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of the Partnership's equity interests in substantially all of its subsidiaries and its interest in HEP.

The Partnership may prepay all loans under the amended credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

All material terms of the credit facility are described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness" in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2011. The Partnership expects to be in compliance with all credit facility covenants for at least the next twelve months.

Non Guarantors. The senior unsecured notes are jointly and severally guaranteed by each of the Partnership's current material subsidiaries (the "Guarantors"), with the exception of its regulated Louisiana subsidiaries (which may only guarantee up to $500.0 million of the Partnership's debt), CDC (the Partnership's joint venture in Denton County, Texas which is not 100% owned by the Partnership) and Crosstex Energy Finance Corporation (a wholly owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Partnership's indebtedness, including the senior unsecured notes). Guarantors may not sell or otherwise dispose of all or substantially all of their properties or assets, or consolidate with or merge into another company if such a sale would cause a default under the terms of the senior unsecured notes. Since certain wholly owned subsidiaries do not guarantee the senior unsecured notes, the condensed consolidating financial statements of the guarantors and non-guarantors for the three months ended March 31, 2012 and 2011 are disclosed below in accordance with Rule 3-10 of Regulation S-X. Comprehensive income (loss) is not included in the condensed consolidating statements of operations of the guarantors and non-guarantors for the three months ended March 31, 2012 and 2011 as these amounts are not considered material.

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Condensed Consolidating Balance Sheets
March 31, 2012

	Guarantors	Non Guarantors	Elimination	Consolidated
	(In thousands)			
ASSETS				
Total current assets	$ 151,699	$ 17,518	$ —	$ 169,217
Property, plant and equipment, net	1,039,254	212,050	—	1,251,304
Total other assets	502,929	—	—	502,929
Total assets	$ 1,693,882	$ 229,568	$ —	$ 1,923,450
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 152,973	$ 4,281	$ —	$ 157,254
Long-term debt	852,883	—	—	852,883
Other long-term liabilities	30,333	—	—	30,333
Partners' capital	657,693	225,287	—	882,980
Total liabilities & partners' capital	$ 1,693,882	$ 229,568	$ —	$ 1,923,450

December 31, 2011

	Guarantors	Non Guarantors	Elimination	Consolidated
	(In thousands)			
ASSETS				

	Guarantors	Non Guarantors	Elimination	Consolidated
Total current assets	$ 189,410	$ 13,346	$ —	$ 202,756
Property, plant and equipment, net	1,026,537	215,364	—	1,241,901
Total other assets	510,671	3	—	510,674
Total assets	$ 1,726,618	$ 228,713	$ —	$ 1,955,331
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 220,811	$ 4,541	$ —	$ 225,352
Long-term debt	798,409	—	—	798,409
Other long-term liabilities	31,111	—	—	31,111
Partners' capital	676,287	224,172	—	900,459
Total liabilities & partners' capital	$ 1,726,618	$ 228,713	$ —	$ 1,955,331

Condensed Consolidating Statements of Operations
For the Three Months Ended March 31, 2012

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 357,153	$ 22,277	$ (7,721)	$ 371,709
Total operating costs and expenses	(347,587)	(9,108)	7,721	(348,974)
Operating income	9,566	13,169	—	22,735
Interest expense, net	(19,373)	(9)	—	(19,382)
Other income	12	—	—	12
Income (loss) before non-controlling interest and income taxes	(9,795)	13,160	—	3,365
Income tax provision	(420)	(4)	—	(424)
Net loss attributable to non-controlling interest	—	(38)	—	(38)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (10,215)	$ 13,194	$ —	$ 2,979

For the Three Months Ended March 31, 2011

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 474,940	$ 21,903	$ (7,073)	$ 489,770
Total operating costs and expenses	(468,150)	(8,710)	7,073	(469,787)
Operating income	6,790	13,193	—	19,983
Interest expense, net	(19,769)	—	—	(19,769)
Other income	113	—	—	113
Income (loss) before non-controlling interest and income taxes	(12,866)	13,193	—	327
Income tax provision	(249)	(4)	—	(253)
Net loss attributable to non-controlling interest	—	(54)	—	(54)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (13,115)	$ 13,243	$ —	$ 128

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CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

Condensed Consolidating Statements of Cash Flow
For the Three Months Ended March 31, 2012

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
Net cash flows provided by (used in) operating activities	$ (1,073)	$ 12,454	$ —	$ 11,381
Net cash flows used in investing activities	$ (40,647)	$ (361)	$ —	$ (41,008)
Net cash flows provided by (used in) financing activities	$ 26,114	$ (12,040)	$ 12,040	$ 26,114

For the Three Months Ended March 31, 2011

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
Net cash flows provided by (used in) operating activities	$ (12,615)	$ 14,435	$ —	$ 1,820
Net cash flows provided by investing activities	$ (20,135)	$ (1,414)	$ —	$ (21,549)
Net cash flows provided by (used in) financing activities	$ 2,869	$ (12,511)	$ 12,511	$ 2,869

(3) Other Long-term Liabilities

Prior to January 1, 2011, the Partnership entered into 9 and 10-year capital leases for certain equipment. Assets under capital leases as of March 31, 2012 are summarized as follows (in thousands):

Compressor equipment	$ 37,199
Less: Accumulated amortization	(11,224)
Net assets under capital leases	$ 25,975

The following are the minimum lease payments to be made in each of the following years indicated for the capital leases in effect as of March 31, 2012 (in thousands):

2012	$ 3,436
2013 through 2016 ($4,582 annually)	18,329

Thereafter	12,099
Less: Interest	(6,260)
Net minimum lease payments under capital lease	27,604
Less: Current portion of net minimum lease payments	(4,448)
Long-term portion of net minimum lease payments	$ 23,156

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(4) Partners' Capital

(a) Cash Distributions

Unless restricted by the terms of the Partnership's credit facility and/or senior unsecured note indenture, 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.

The Partnership's fourth quarter 2011 distribution on its common and preferred units of $0.32 per unit was paid on February 14, 2012. The Partnership declared a first quarter 2012 distribution on its common and preferred units of $0.33 per unit to be paid on May 15, 2012.

(b) Earnings per Unit and Dilution Computations

The Partnership had common units and preferred units outstanding during the three months ended March 31, 2012 and March 31, 2011.

The preferred units are entitled to a quarterly distribution equal to the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Income is allocated to the preferred units in an amount equal to the quarterly distribution with respect to the period earned.

As required under FASB ASC 260-10-45-61A, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, for earnings per unit calculations. The following table reflects the computation of basic earnings per limited partner units for the periods presented (in thousands except per unit amounts):

	Three Months Ended March 31,	
	2012	2011
Limited partners' interest in net income	$ (1,803)	$ (3,615)
Distributed earnings allocated to:		
Common units (1)(2)	$ 16,783	$ 14,625
Unvested restricted units (1)(2)	339	299
Total distributed earnings	$ 17,122	$ 14,924
Undistributed loss allocated to:		
Common units	$ (18,551)	$ (18,231)
Unvested restricted units	(374)	(308)
Total undistributed loss	$ (18,925)	$ (18,539)
Net loss allocated to:		
Common units	$ (1,768)	$ (3,606)
Unvested restricted units	(35)	(9)
Total limited partners' interest in net income	$ (1,803)	$ (3,615)
Basic and diluted net loss per unit:		
Basic and diluted common unit	$ (0.03)	$ (0.07)

(1) Three months ended March 31, 2012 represents a declared distribution of $0.33 per unit payable on May 15, 2012.
(2) Three months ended March 31, 2011 represents a declared distribution of $0.29 per unit paid on May 13, 2011.

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The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three months ended March 31, 2012 and 2011 (in thousands):

	Three Months Ended March 31,	
	2012	2011
Basic and diluted weighted average units outstanding:		
Weighted average limited partner common units outstanding	50,857	50,472

All common unit equivalents were antidilutive in the three months ended March 31, 2012 and March 31, 2011 because the limited partners were allocated net losses in these periods.

The general partner is entitled to a 2.0% distribution with respect to all distributions made to common unitholders. If the distributions are in excess of $0.2125 per unit, distributions are made 98.0% to the common and preferred unitholders and 2.0% to the general partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved.

When quarterly distributions are made pro-rata to common and preferred unitholders, net income for the general partner consists of incentive distributions to the extent earned, a deduction for stock-based compensation attributable to CEI's stock options and restricted shares and 2.0% of the original Partnership's net income (loss) adjusted for the CEI stock-based compensation specifically allocated to the general partner. When quarterly distributions are made solely to the preferred unitholders, the net income for the general partner consists of the CEI stock-based compensation deduction and 2.0% of the Partnership's net income (loss) after the allocation of income to the preferred unitholders with respect to their preferred distribution adjusted for the CEI stock-based compensation specifically allocated to the general partner.

Under the quarterly incentive distribution provisions, generally the Partnership's general partner is entitled to 13.0% of amounts the Partnership distributes in excess of $0.25 per unit, 23.0% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48.0% of amounts the Partnership distributes in excess of $0.375 per unit. The net income (loss) allocated to the general partner is as follows (in thousands):

	Three Months Ended March 31, 2012	2011
Income allocation for incentive distributions	$ 979	$ 398
Stock-based compensation attributable to CEI's restricted shares	(1,133)	(941)
2% general partner interest in net income	83	21
General partner share of net income	$ (71)	$ (522)

(5) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership accounts for share-based compensation in accordance with FASB ASC 718, which requires that compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements.

The Partnership and CEI each have similar unit or share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plan 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 condensed consolidated financial statements with respect to these plans are as follows (in thousands):

	Three Months Ended March 31, 2012	2011
Cost of share-based compensation charged to general and administrative expense	$ 2,174	$ 1,726
Cost of share-based compensation charged to operating expense	324	464
Total amount charged to income	$ 2,498	$ 2,190

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(b) Restricted Units

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the three months ended March 31, 2012 is provided below:

Crosstex Energy, L.P. Restricted Units:	Three Months Ended March 31, 2012 Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	949,844	$ 10.45
Granted	330,200	16.89
Vested*	(216,447)	6.13
Forfeited	(3,245)	13.38
Non-vested, end of period	1,060,352	$ 13.33
Aggregate intrinsic value, end of period (in thousands)	$ 18,121	

* Vested units include 60,401 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued restricted units in 2012 to officers and other employees. These restricted units typically vest at the end of three years and are included in the restricted units outstanding and the current share-based compensation cost calculations at March 31, 2012.

A summary of the restricted units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the three months ended March 31, 2012 and 2011 are provided below (in thousands):

Crosstex Energy, L.P. Restricted Units:	Three Months Ended March 31, 2012	2011
Aggregate intrinsic value of units vested	$ 3,511	$ 4,239
Fair value of units vested	$ 1,327	$ 3,173

As of March 31, 2012, there was $8.7 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.

(c) Unit Options

A summary of the unit option activity for the three months ended March 31, 2012 is provided below:

Crosstex Energy, L.P. Unit Options:	Three Months Ended March 31, 2012 Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	451,574	$ 6.99
Exercised	(34,668)	5.17
Forfeited	(3,871)	18.38
Outstanding, end of period	413,035	$ 7.05
Options exercisable at end of period	345,668	
Weighted average contractual term (years) end of period:		
Options outstanding	6.9	
Options exercisable	6.7	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 4,572	
Options exercisable	$ 3,825	

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A summary of the unit options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value of units exercised (value per Black-Scholes-Merton option pricing model at date of grant) during the three months ended March 31, 2012 and March 31, 2011 are provided below (in thousands):

Crosstex Energy, L.P. Unit Options:	Three Months Ended March 31, 2012	2011
Intrinsic value of unit options exercised	$ 411	$ 506
Fair value of unit options vested	$ 277	$ 325

As of March 31, 2012, there was $0.2 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized during 2012.

(d) Crosstex Energy, Inc.'s Restricted Stock

CEI's restricted shares are valued at their fair value at the date of grant which is equal to the market value of the common stock on such date. A summary of the restricted share activities for the three months ended March 31, 2012 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Three Months Ended March 31, 2012 Number of Shares	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,221,351	$ 7.40
Granted	427,990	13.38
Vested*	(216,447)	4.65
Forfeited	(4,551)	8.73
Non-vested, end of period	1,428,343	$ 9.61
Aggregate intrinsic value, end of period (in thousands)	$ 20,197	

* Vested shares include 58,247 shares withheld for payroll taxes paid on behalf of employees.

CEI issued restricted shares in 2012 to officers and other employees. These restricted shares typically vest at the end of three years and are included in restricted shares outstanding and the current share-based compensation cost calculations at March 31, 2012.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value of shares vested (market value at date of grant) during the three months ended March 31, 2012 and March 31, 2011 are provided below (in thousands):

Crosstex Energy, Inc. Restricted Shares:	Three Months Ended March 31, 2012	2011
Aggregate intrinsic value of shares vested	$ 2,736	$ 2,578
Fair value of shares vested	$ 1,006	$ 2,890

As of March 31, 2012, there was $8.6 million of unrecognized compensation costs related to non-vested CEI restricted shares. The cost is expected to be recognized over a weighted average period of 2.2 years.

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(e) Crosstex Energy, Inc.'s Stock Options

CEI stock options have not been granted to officers or employees of the Partnership since 2005. There are 37,500 CEI stock options vested and exercisable at March 31, 2012.

(6) Derivatives

Commodity Swaps

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge price and location risks 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 accounting hedges. These transactions include "swing swaps," "third party on-system financial swaps," "storage swaps," "basis swaps," "processing margin swaps," "liquids swaps" and "put options." 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. Storage swap transactions protect against changes in the value of products that the Partnership has stored to serve various operational requirements (gas) or has in inventory due to short term constraints in moving the product to market (liquids). Basis swaps are used to hedge basis location price risk due to buying gas into one of the Partnership's systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge fractionation spread risk at the Partnership's processing plants relating to the option to process versus bypassing the Partnership's equity gas. Liquids financial swaps are used to hedge price risk on percent of liquids (POL) contracts. Put options are purchased to hedge against declines in pricing and as such represent options, not obligations, to sell the related underlying volumes at a fixed price.

The components of loss on derivatives in the condensed consolidated statements of operations relating to commodity swaps are provided below (in thousands):

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Change in fair value of derivatives that do not qualify for hedge accounting	$ 1,181	$ 1,555
Realized losses on derivatives	1,026	1,761
Ineffective portion of derivatives qualifying for hedge accounting	(38)	19
Net losses related to commodity swaps	$ 2,169	$ 3,335
Put option premium mark to market	—	86
Losses on derivatives	$ 2,169	$ 3,421

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

	March 31, 2012	December 31, 2011
Fair value of derivative assets — current, designated	$ 48	$ 151
Fair value of derivative assets — current, non-designated	1,226	2,716
Fair value of derivative assets — long term, non-designated	131	—
Fair value of derivative liabilities — current, designated	(246)	(702)
Fair value of derivative liabilities — current, non-designated	(4,597)	(4,885)
Fair value of derivative liabilities — long term, non-designated	(110)	—
Net fair value of derivatives	$ (3,548)	$ (2,720)

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets as of March 31, 2012 (all gas volumes are expressed in MMBtu's and liquids volumes are expressed in

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gallons). The remaining term of the contracts extend no later than December 2013 for derivatives. Changes in the fair value of the Partnership's mark to market derivatives 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. The ineffective portion is recorded in earnings immediately.

Transaction Type	March 31, 2012 Volume (In thousands)	March 31, 2012 Fair Value (In thousands)
*Cash Flow Hedges:**		
Liquids swaps (short contracts)	(4,584)	$ (198)
Total swaps designated as cash flow hedges		$ (198)
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	195	$ —
Physical offsets to swing swap transactions (short contracts)	(195)	—
Swing swaps (short contracts)	(450)	(10)
Physical offsets to swing swap transactions (long contracts)	450	—
Basis swaps (long contracts)	2,830	(10)
Physical offsets to basis swap transactions (short contracts)	(2,830)	4,509
Basis swaps (short contracts)	(2,830)	17
Physical offsets to basis swap transactions (long contracts)	2,830	(6,267)
Processing margin hedges — liquids (short contracts)	(13,569)	357
Processing margin hedges — gas (long contracts)	1,600	(2,331)
Processing margin hedges — gas (short contracts)	(187)	287

Liquids swaps — (short contracts)	(4,393)	(57)
Storage swap transactions — gas (short contracts)	(290)	155
Total mark to market derivatives		$ (3,350)

* All are gas contracts, volume in MMBtu's, except for liquids swaps (designated or non-designated) and processing margin hedges - liquids (volume in gallons).

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. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of March 31, 2012 of $5.9 million would be reduced to $4.7 million due to the netting feature.

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Impact of Cash Flow Hedges

The impact of realized gains or losses from derivatives designated as cash flow hedge contracts in the condensed consolidated statements of operations is summarized below (in thousands):

	Three Months Ended March 31,	
Decrease in Midstream Revenue	**2012**	**2011**
Liquids realized loss included in Midstream revenue	$ (12)	$ (660)

Natural Gas

As of March 31, 2012, the Partnership has no balances in accumulated other comprehensive income related to natural gas.

Liquids

As of March 31, 2012, an unrealized derivative fair value net loss of $0.2 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive loss, all of which is expected to be reclassified into earnings through March 2013. 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 is not reflected in the above table.

Derivatives Other Than Cash Flow Hedges

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

	Maturity Periods			
	Less than one year	**One to two years**	**More than two years**	**Total fair value**
March 31, 2012	$ (3,371)	$ 21	$ —	$ (3,350)

(7) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

FASB ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Partnership's derivative contracts primarily consist of commodity swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in hierarchy.

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in thousands):

	March 31, 2012 Level 2	**December 31, 2011 Level 2**
Commodity Swaps*	$ (3,548)	$ (2,720)
Total	$ (3,548)	$ (2,720)

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income at each measurement date. The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction transaction adjusted for credit risk of the Partnership and/or the counterparty as required under FASB ASC 820.

Fair Value of Financial Instruments

The estimated fair value of the Partnership's financial instruments has been determined by the Partnership using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount the Partnership could realize upon the sale or refinancing of such financial instruments (in thousands):

	March 31, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 852,883	$ 910,219	$ 798,409	$ 882,500
Obligations under capital lease	$ 27,604	$ 29,776	$ 28,367	$ 27,637

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The Partnership had $139.0 million in borrowings under its revolving credit facility included in long-term debt as of March 31, 2012 and $85.0 million at December 31, 2011. As borrowings under the credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of March 31, 2012 and December 31, 2011, the Partnership also had borrowings totaling $713.9 million and $713.4 million, net of discount, respectively, under senior unsecured notes with a fixed rate of 8.875%. The fair value of the senior unsecured notes as of March 31, 2012 and December 31, 2011 was based on Level I inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level II inputs from third-party banks.

(8) Commitments and Contingencies

(a) Employment and Severance Agreements

Certain members of management of the Partnership are parties to employment and/or severance agreements with the general partner. The employment and severance agreements provide those managers with severance payments in certain circumstances and, in the case of employment agreements, 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 LIG Pipeline Company and its subsidiaries on April 1, 2004. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. The seller, AEP, has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third party company pursuant to which the remediation costs associated with these sites have been assumed by this third party company that specializes in remediation work. The Partnership does not expect to incur any material liability with these sites; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations.

(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.

On June 7, 2010, Formosa Plastics Corporation, Texas, Formosa Plastics Corporation, America, Formosa Utility Venture, Ltd., and Nan Ya Plastics Corporation, America filed a lawsuit against Crosstex Energy, Inc., Crosstex Energy, L.P., Crosstex Energy GP, L.P., Crosstex Energy GP, LLC, Crosstex Energy Services, L.P., and Crosstex Gulf Coast Marketing, Ltd. in the 24th Judicial District Court of Calhoun County, Texas, asserting claims for negligence, *res ipsa loquitor*, products liability and strict liability relating to the

alleged receipt by the plaintiffs of natural gas liquids into their facilities from facilities operated by the Partnership. The amended petition alleges that the plaintiffs have incurred at least $35.0 million in damages, including damage to equipment and lost profits. The Partnership has submitted the claim to its insurance carriers and intends to vigorously defend the lawsuit. The Partnership believes that any recovery would be within applicable policy limits. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

At times, the Partnership's gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain provided under state law. As a result, the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

The Partnership (or its subsidiaries) is defending a number of lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. The Partnership intends to appeal the matter and will post a bond to secure the judgment pending its resolution. The Partnership has accrued $2.0 million related to this matter as of March 31, 2012 and reflected the related expense in operating expenses in the fourth quarter of 2011. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

(9) Segment Information

Identification of operating segments is based principally upon regions served. The Partnership's reportable segments consist of the natural gas gathering, processing and transmission operations located in north Texas and in the Permian Basin in west Texas (NTX), the pipelines and processing plants located in Louisiana (LIG) and the south Louisiana processing and NGL assets (PNGL). Operating activity for assets sold in the comparative periods that was not considered discontinued operations as well as intersegment eliminations is shown in the corporate segment. The Partnership's sales are derived from external domestic customers.

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

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

	LIG	NTX	PNGL (In thousands)	Corporate	Totals
Three Months Ended March 31, 2012:					
Sales to external customers	$ 146,697	$ 64,681	$ 160,331	$ —	$ 371,709
Sales to affiliates	$ 72,810	$ 31,484	$ 45,545	$ (149,839)	$ —
Purchased gas and NGLs	$ (189,220)	$ (50,021)	$ (182,554)	$ 149,839	$ (271,956)
Operating expenses	$ (7,936)	$ (13,151)	$ (6,719)	$ —	$ (27,806)
Segment profit	$ 22,351	$ 32,993	$ 16,603	$ —	$ 71,947
Gain (loss) on derivatives	$ 102	$ (2,263)	$ (8)	$ —	$ (2,169)
Depreciation, amortization and impairments	$ (3,153)	$ (20,433)	$ (7,959)	$ (633)	$ (32,178)
Capital expenditures	$ 8	$ 13,156	$ 15,662	$ 454	$ 29,280
Identifiable assets	$ 286,911	$ 1,092,530	$ 463,249	$ 80,760	$ 1,923,450
Three Months Ended March 31, 2011:					
Sales to external customers	$ 204,918	$ 80,966	$ 203,886	$ —	$ 489,770
Sales to affiliates	22,322	21,585	485	(44,392)	—
Purchased gas and NGLs	(195,503)	(63,159)	(185,663)	44,392	(399,933)
Operating expenses	(8,067)	(11,352)	(5,625)	—	(25,044)
Segment profit	$ 23,670	$ 28,040	$ 13,083	$ —	$ 64,793
Loss on derivatives	$ (2,685)	$ (716)	$ (20)	$ —	$ (3,421)
Depreciation, amortization and impairments	$ (3,142)	$ (17,720)	$ (7,713)	$ (1,078)	$ (29,653)
Capital expenditures	$ 1,550	$ 18,203	$ 4,083	$ 487	$ 24,323
Identifiable assets	$ 323,881	$ 1,110,852	$ 489,147	$ 35,445	$ 1,959,325

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Segment profits	$ 71,947	$ 64,793
General and administrative expenses	(14,963)	(11,755)
Loss on derivatives	(2,169)	(3,421)
Gain on sale of property	98	19
Depreciation, amortization and impairments	(32,178)	(29,653)
Operating income	$ 22,735	$ 19,983

(10) Subsequent Event

Investment in HEP. On April 4, 2012, the Partnership made a $47.4 million payment to HEP related to HEP's acquisition of substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas which was funded by the Partnership's credit facility. After this capital contribution, the Partnership has contributed an aggregate of $87.3 million and has an individual ownership interest in HEP of approximately 30.6 percent.

Riverside Fractionation Facility Expansion. On May 7, 2012, the Partnership announced its plans to increase its capacity to transload crude oil from rail cars to both barges and pipeline at its Riverside fractionation facility in southern Louisiana from approximately 4,500 barrels of crude oil per day to approximately 15,000 barrels of crude per day. The Phase I modification of the Riverside facility, which allowed crude as well as NGLs to be transloaded from rail to barge, was operational in January 2012. The Phase II development at the Riverside facility will include new storage tank facilities, upgraded pipeline connections and improved barge delivery capabilities on the Mississippi River. Construction of the Phase II expansion project at the Riverside facility will begin in late June 2012 and is expected be operational in the first quarter of 2013. The Riverside facility expansion project is expected to cost approximately $16 million. The Partnership has entered into a long-term agreement, which supports the expansion.

Clearfield Acquisition. On May 8, 2012, the Partnership announced its agreement to acquire privately held Clearfield Energy, Inc. ("Clearfield") for approximately $210 million in cash at closing subject to certain adjustments (the "Clearfield Acquisition"). Clearfield is a well-established crude oil, condensate and water services company with operations in Ohio, Kentucky and West Virginia. Clearfield's business includes crude oil pipelines, a barge loading terminal on the Ohio River, a rail loading terminal on the Ohio Central Railroad network, a trucking fleet, and brine water disposal wells.

The Partnership plans to fund the Clearfield Acquisition with a combination of debt and equity. The closing of the Clearfield Acquisition, which is expected in July 2012, is subject to the satisfaction of customary closing conditions, including applicable regulatory approvals, if any.

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

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

Overview

We are a Delaware limited partnership formed on July 12, 2002. Our primary focus is on the gathering, processing, transmission and marketing of natural gas and natural gas liquids (NGLs), which we manage as regional reporting segments of midstream activity. We recently added crude oil terminal facilities in south Louisiana to provide access for crude oil producers to the premium markets in this area. Our geographic focus is in the north Texas Barnett shale (NTX) and in Louisiana which has two reportable business segments (the pipelines and processing plants located in Louisiana, or LIG, and the south Louisiana processing and NGL assets, or PNGL). During 2011, we gained a presence in the Permian Basin in west Texas through a joint project with Apache Corporation, which is included in our NTX segment and also gained access in the Eagle Ford shale in south Texas by our equity investment in Howard Energy Partners ("HEP"), which is included with our corporate assets for segment reporting.

We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas and NGLs for a margin, or to gather, process, transport or market natural gas and NGLs for a fee. We earn a volume based fee for providing crude oil services. We define gross operating margin as operating revenue minus cost of purchased gas and NGLs. Gross operating margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below.

Our gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, the volumes of NGLs handled at our fractionation facilities and the volumes of crude oil handled at our crude terminals. 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;
- fractionating and marketing the recovered NGLs;
- providing compression services; and
- providing crude oil terminal services.

We generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas at the market index. 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. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, on occasion we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as our margin. Changes in the basis spread can increase or decrease our margins.

One contract (the "Delivery Contract") has a term to 2019 that obligates us to supply approximately 150,000 MMBtu/d of gas. At the time that we entered into the Delivery Contract in 2008, we had dedicated supply sources in the Barnett Shale that exceeded the delivery obligations under the Delivery Contract. Our agreements with these suppliers generally provided that the purchase price for the gas was equal to a portion of our sales price for such gas less certain fees and costs. Accordingly, we were initially able to generate a positive margin under the Delivery Contract. However, since entering into the Delivery Contract, there has been both (1) a reduction in the gas available under our supply contracts and (2) the discovery of other shale reserves, most notably the Haynesville and the Marcellus Shales, which has increased the supplies available to east coast markets and reduced the basis spread between north Texas-area production and the market indices used in the Delivery Contract. Due to these factors, we have had to purchase a portion

of the gas necessary to fulfill our obligations under the Delivery Contract at market prices, resulting in negative margins under the Delivery Contract.

We have recorded a loss of approximately $3.8 million during the three months ended March 31, 2012 on the Delivery Contract. We currently expect that we will record an additional loss of approximately $11.8 million on the Delivery Contract for the remainder of the year ending December 31, 2012. This estimate is based on forward prices, basis spreads and other market assumptions as of March 31, 2012. These assumptions are subject to change if market conditions change during the remainder of 2012, and actual results under the Delivery Contract in 2012 could be substantially different from our current estimates, which may result in a greater loss than currently estimated.

We also realize gross operating margins from our processing services primarily through three different contract arrangements: processing margins (margin), percentage of liquids (POL) or fixed-fee based. Under margin contract arrangements our gross operating margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Under fixed-fee based contracts our gross operating margins are driven by throughput volume. See "Item 3. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk."

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, property insurance, property taxes, repair and maintenance expenses, contract services 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 or liquids moved through the asset.

Our general and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Recent Developments

Credit Facility. On January 24, 2012, we amended our credit facility. This amendment increased our borrowing capacity from $485.0 million to $635.0 million and amended certain terms in the facility to provide additional financial flexibility during the remaining four-year term of the facility as described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation — Indebtedness" in our Annual Report on Form 10-K for the year ended December 31, 2011.

Investment in Limited Liability Company. On March 15, 2012, HEP announced that it entered into a definitive agreement to acquire substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas. This acquisition was funded primarily by capital contributions by the Partnership and other unrelated parties. In June 2011, the Partnership had originally invested $35.0 million for an ownership interest in HEP of about 35.0 percent. The capital contribution related to the Meritage acquisition was a total of $52.3 million, with $4.9 million paid in March 2012 and the remaining $47.4 million paid in April 2012 which was funded by the Partnership's credit facility.

After closing of the acquisition and including initial investments, the Partnership has contributed a total of $87.3 million for an ownership interest in HEP of approximately 30.6 percent. HEP operates and manages midstream services as well as pipeline and plant construction primarily in the Eagle Ford shale in south Texas.

Riverside Fractionation Facility Expansion. On May 7, 2012, the Partnership announced its plans to increase its capacity to transload crude oil from rail cars to both barges and pipeline at its Riverside fractionation facility in southern Louisiana from approximately 4,500 barrels of crude oil per day to approximately 15,000 barrels of crude per day. The Phase I modification of the Riverside facility, which allowed crude as well as NGLs to be transloaded from rail to barge, was operational in January 2012. The Phase II development at the Riverside facility will include new storage tank facilities, upgraded pipeline connections and improved barge delivery capabilities on the Mississippi River. Construction of the Phase II expansion project at Riverside will begin in late June 2012 and is expected be operational in the first quarter of 2013. The expansion project is expected to cost approximately $16 million. The Partnership has entered into a long-term agreement, which supports the expansion.

Clearfield Acquisition. On May 8, 2012, the Partnership announced its agreement to acquire privately held Clearfield Energy, Inc. ("Clearfield") for approximately $210 million in cash at closing, subject to certain adjustments (the "Clearfield Acquisition"). Clearfield is a crude oil, condensate and water services company with operations in Ohio, Kentucky and West Virginia. Clearfield currently moves approximately 30 percent of the oil production in Ohio and provides a solid entry into the Utica Shale play where major producers have acquired significant acreage positions. The Partnership expects this acquisition to be immediately accretive to distributable cash flow.

The Clearfield Acquisition further diversifies the Partnership's asset base in terms of geography and service offerings, representing an important strategic step for the Partnership into crude and condensate services. As Utica Shale production expands, the Partnership plans to leverage Clearfield's first-mover position in crude and condensate services in the region, which will drive further growth. The Partnership believes its core capabilities and strong financial performance will enable it to leverage Clearfield's strategically positioned assets and operational platform to accelerate growth. This platform will better enable the Partnership to compete for natural gas gathering and processing opportunities in the emerging Utica Shale play.

Clearfield's assets include a 4,500-barrel-per-hour crude oil barge loading terminal on the Ohio River, a 28,000-barrel-per day crude oil rail loading terminal on the Ohio Central Railroad network which is expected to expand to a 56,000-barrel-per-day facility by end-of-year, and 200 miles of crude oil pipelines in Ohio and West Virginia. The assets also include 100,000 barrels of above ground storage, six existing brine water disposal wells with two under development and an extensive fleet of trucks with a total capacity of 35,000 barrels per day. In addition, Clearfield owns more than 2,500 miles of unused right of way.

The Partnership plans to fund the Clearfield Acquisition with a combination of debt and equity. The closing of the Clearfield Acquisition, which is expected to occur in July 2012, is subject to the satisfaction of customary closing conditions, including applicable regulatory approvals, if any.

Non-GAAP Financial Measures

We include the following non-generally accepted accounting principles, or non-GAAP, financial measures: Adjusted earnings before interest, taxes, depreciation and amortization, or adjusted EBITDA, and gross operating margin.

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We define adjusted EBITDA as net income plus interest expense, provision for income taxes, depreciation and amortization expense, impairments, stock-based compensation, (gain) loss on noncash derivatives, and minority interest; less gain on sale of property. Adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our general partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Adjusted EBITDA is one of the critical inputs into the financial covenants within our credit facility. The rates we pay for borrowings under our credit facility are determined by the ratio of our debt to adjusted EBITDA. The calculation of these ratios allows for further adjustments to adjusted EBITDA for recent acquisitions and dispositions.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted EBITDA may not be comparable to similarly titled measures of other companies because other entities may not calculate adjusted EBITDA in the same manner.

Adjusted EBITDA does not include interest expense, income taxes or depreciation and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following table provides a reconciliation of adjusted EBITDA to net income (loss):

	Three Months Ended March 31,	
	2012	**2011**
	(In millions)	

Net income attributable to Crosstex Energy, L.P.	$	3.0	$	0.1
Interest expense		19.4		19.8
Depreciation and amortization		32.2		29.7
Gain on sale of property		(0.1)		—
Stock-based compensation		2.5		2.2
Other (a)		1.5		1.8
Adjusted EBITDA	$	58.5	$	53.6

(a) Includes financial derivatives marked-to-market; income taxes; and minority interest.

We define gross operating margin, generally, as revenues minus cost of purchased gas and NGLs. We present gross operating margin by segment in "Results of Operations." We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because our business is generally to purchase and resell natural gas for a margin or to gather, process, transport or market natural gas and NGLs for a fee. Operating expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. These expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. We do not deduct operating expenses from total revenue in calculating gross operating margin because we separately evaluate commodity volume and price changes in these margin amounts. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful

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than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of gross operating margin to operating income:

	Three Months Ended March 31,			
	2012		2011	
	(In millions)			
Total gross operating margin	$	99.8	$	89.8
Add (deduct):				
Operating expenses		(27.8)		(25.0)
General and administrative expenses		(15.0)		(11.8)
Gain on sale of property		0.1		—
Loss on derivatives		(2.2)		(3.4)
Depreciation and amortization		(32.2)		(29.7)
Operating income	$	22.7	$	19.9

Results of Operations

Set forth in the table below is certain financial and operating data for the periods indicated. We manage our operations by focusing on gross operating margin which we define as operating revenue minus cost of purchased gas and NGLs as reflected in the table below.

	Three Months Ended March 31,			
	2012		2011	
	(Dollars in millions)			
LIG Segment				
Revenues	$	219.5	$	227.2
Purchased gas and NGLs		(189.2)		(195.5)
Total gross operating margin	$	30.3	$	31.7
NTX Segment				
Revenues	$	96.2	$	102.6
Purchased gas and NGLs		(50.0)		(63.2)
Total gross operating margin	$	46.2	$	39.4
PNGL Segment				
Revenues	$	205.9	$	204.4
Purchased gas and NGLs		(182.6)		(185.7)
Total gross operating margin	$	23.3	$	18.7
Corporate				
Revenues	$	(149.8)	$	(44.4)
Purchased gas and NGLs		149.8		44.4
Total gross operating margin	$	—	$	—
Total				
Revenues	$	371.8	$	489.8
Purchased gas and NGLs		(272.0)		(400.0)
Total gross operating margin	$	99.8	$	89.8
Midstream Volumes:				
LIG				
Gathering and Transportation (MMBtu/d)		900,000		938,000
Processing (MMBtu/d)		262,000		258,000
NTX				
Gathering and Transportation (MMBtu/d)		1,181,000		1,054,000
Processing (MMBtu/d)		319,000		214,000
PNGL				

Processing (MMBtu/d)	904,000	921,000
NGL Fractionation (Gals/d)	1,179,000	1,132,000
Commercial Services (MMBtu/d)	12,000	113,000

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Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

Gross Operating Margin. Gross operating margin was $99.8 million for thethree months ended March 31, 2012 compared to $89.8 million for the three months ended March 31, 2011, an increase of $10.0 million, or 11.1%. The overall increase was due to an increase in throughput on our systems and an increase in NGL fractionation and marketing activity. The following provides additional details regarding this change in gross operating margin:

- The NTX segment had gross operating margin improvement of $6.8 million for the three months ended March 31, 2012 compared to the three months ended March 31, 2011. An increase in throughput volume on the gathering and transmission assets in north Texas due to the Benbrook and Fossil Creek expansion projects was the primary contributor to a gross operating margin increase of $4.4 million. The north Texas processing plants also had a gross operating margin increase of $2.4 million for the comparable periods primarily due to increased supply from the expansion projects. In addition, the gas processing facilities located in the Permian Basin commenced operation during the first quarter of 2012 and contributed $0.8 million to gross operating margin. These increases were partially offset by an increase in losses of $0.8 million on the Delivery Contract discussed more fully under "Overview".

- The PNGL segment had gross operating margin increase of $4.6 million for the three months ended March 31, 2012 compared to the three months ended March 31, 2011. Our NGL fractionation and marketing activities generated $3.3 million of the gross operating margin increase. The primary contributors to the gross operating margin increase from NGL activities were $1.6 million of gross operating margin from the sale of NGLs in the first quarter of 2012 upon expiration of a third- party fractionation agreement for the Sabine processing plant and $1.3 million of gross operating margin from the Eunice fractionator which was restarted in mid-2011. The PNGL segment also includes our new crude oil terminal activity in south Louisiana, which contributed $0.8 million to PNGL's gross operating margin during the three months ended March 31, 2012. The south Louisiana processing plants contributed a combined gross operating margin increase of $0.5 million.

- The LIG segment contributed a decrease in gross operating margin of $1.5 million for the three months ended March 31, 2012 compared to the three months ended March 31, 2011. Gross operating margins increased by $1.9 million on the LIG gathering and transmission assets. Gross operating margins decreased by $3.4 million related to gas processing activities. The Plaquemine and Gibson plants contributed a slight increase of $0.8 million in gross operating margin between periods. Processing margins earned from gas processed for our account by a third-party processor declined by $4.2 million between periods due to volume reductions attributed to expiration of contracts and due to lower margins under renegotiated contracts.

Operating Expenses. Operating expenses were $27.8 million for the three months ended March 31, 2012 compared to $25.0 million for the three months ended March 31, 2011, an increase of $2.8 million, or 11.2%. The increase is primarily a result of the following:

- our labor and benefits expense increased by $1.0 million related to an increase in employee headcount for activity related to project expansions in the North Texas segment, including the Permian Basin processing facilities and the PNGL segment;

- we experienced an increase of $0.7 million in material and supplies expenses for costs related to compressor overhauls performed in 2012; and

- our ad valorem tax expense increased by $0.7 million.

General and Administrative Expenses. General and administrative expenses were $15.0 million for the three months ended March 31, 2012 compared to $11.8 million for the three months ended March 31, 2011, an increase of $3.2 million, or 27.1%. The increase is primarily due to the following:

- our labor and benefits expense increased by $1.5 million related to an increase in headcount to support project expansions; and

- we experienced an increase of $1.1 million in fees and services related to legal and other professional fees.

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Gain/Loss on Derivatives. We had a loss on derivatives of $2.2 million for the three months ended March 31, 2012 compared to a loss of $3.4 million for the three months ended March 31, 2011. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Three Months Ended March 31,			
	2012		2011	
	Total	Realized	Total	Realized
Basis swaps	$ 2.3	$ 0.7	$ 0.6	$ 0.8
Processing margin hedges	0.2	0.9	2.7	1.2
Other	(0.3)	(0.6)	0.1	(0.2)
Net losses related to commodity swaps	$ 2.2	$ 1.0	$ 3.4	$ 1.8

Depreciation and Amortization. Depreciation and amortization expenses were $32.2 million for the three months ended March 31, 2012 compared to $29.7 million for the three months ended March 31, 2011, an increase of $2.5 million, or 8.4%. The increase includes $1.8 million due to intangible amortization related to the downward revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in North Texas. In addition, depreciation increased by $0.7 million due primarily to our Permian and Benbrook assets placed in service during the first quarter of 2012.

Interest Expense. Interest expense was $19.4 million for the three months ended March 31, 2012 compared to $19.8 million for the three months ended March 31, 2011, a decrease of $0.4 million, or 2.0%. Net interest expense consists of the following (in millions):

	Three Months Ended March 31,	
	2012	2011
Senior notes	$ 16.6	$ 16.6
Bank credit facility	1.6	1.3
Amortization of debt issue costs	1.2	1.6

Other	—	0.3
Total	$ 19.4	$ 19.8

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, 2011.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $11.4 million for the three months ended March 31, 2012 compared to $1.8 million for three months ended March 31, 2011. Income before non-cash income and expenses and changes in working capital for comparative periods were as follows (in millions):

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Income before non-cash income and expenses	$ 40.3	$ 35.4
Changes in working capital	$ (28.9)	$ (33.6)

The increase in cash flow from income before non-cash income and expenses of $4.9 million from 2011 to 2012 resulted from an increase in gross operating margin.

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Cash Flows from Investing Activities. Net cash used in investing activities was $41.0 million for the three months ended March 31, 2012 and $21.5 million for the three months ended March 31, 2011. Our primary investing outflows were capital expenditures, net of accrued amounts, as follows (in millions):

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Growth capital expenditures	$ 33.4	$ 19.2
Maintenance capital expenditures	2.9	2.4
Investment in Howard Energy Partners	4.9	—
Total	$ 41.2	$ 21.6

Cash Flows from Financing Activities. Net cash provided by financing activities was $26.1 million for the three months ended March 31, 2012 and $2.9 million for the three months ended March 31, 2011. Our primary financing activities consist of the following (in millions):

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Net borrowings (repayments) under bank credit facility	$ 54.0	$ 16.0
Net repayments under capital lease obligations	(0.8)	(0.7)
Debt refinancing costs	(1.2)	(0.1)

Distributions to unitholders and our general partner also represent a primary use of cash in financing activities. Total cash distributions made during the three months ended March 31, 2012 and 2011 were as follows (in millions):

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Common units	$ 16.6	$ 13.3
Preferred units	4.7	3.8
General partner interest (including incentive distribution rights)	1.2	0.4
Total	$ 22.5	$ 17.5

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. We borrow money under our credit facility to fund checks as they are presented. As of March 31, 2012, we had approximately $436.2 million of available borrowing capacity under this facility. Changes in drafts payable for the three months ended March 31, 2012 and 2011 were as follows (in millions):

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Increase (decrease) in drafts payable	$ (2.7)	$ 6.3

Potential Changes in use of Sabine Plant during 2012. Currently, the Partnership's Sabine plant has a contract with a third-party to fractionate the raw-make NGLs produced by the plant. This contract, which was scheduled to expire on March 1, 2012, was extended through June 30, 2012 and may be extended on a month-to-month basis thereafter. The Partnership will negotiate with this third-party to establish a long-term fractionation agreement. If this third-party ceases to fractionate the produced NGLs from the Sabine plant after June 30, 2012 and the Partnership is unsuccessful in determining another alternative for our Sabine customers, the Partnership will cease operation of the Sabine plant. Although the Partnership does not have specific plans at this time to relocate the Sabine plant if it is idled, the Partnership may utilize it elsewhere in its operations. The net book value of the Sabine plant was $47.4 million (including $13.7 million of intangible assets attributable to customer relationships) as of March 31, 2012. If the plant is idled on a long-term basis, an impairment may be recorded to expense

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the non-recoverable costs associated with the plant's current location, which are estimated to be less than $28.0 million based on the net book value as of March 31, 2012.

Capital Requirements. During the three months ended March 31, 2012, capital investments were $38.3 million (including $4.9 million related to HEP), which were funded by internally generated cash flow and from borrowings under our credit facility. Our current growth capital spending projection for 2012 is approximately $286.0 million related to identified growth projects including $31.8 million incurred during the first three months of 2012. Our remaining 2012 projected capital spend for growth capital includes approximately $170.0 million related to projected expenditures for the expansion of the Cajun-Sibon NGL pipeline and $47.4 million related to an additional investment in our equity interest in HEP.

Off-Balance Sheet Arrangements. No off-balance sheet arrangements existed as of March 31, 2012.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of March 31, 2012 is as follows (in millions):

	Payments Due by Period						
	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt obligations	$ 725.0	$ —	$ —	$ —	$ —	$ —	$ 725.0
Bank credit facility	139.0	—	—	—	—	139.0	—
Interest payable on fixed long-term debt obligations	385.0	32.2	64.3	64.3	64.3	64.3	95.6
Capital lease obligations	33.9	3.4	4.6	4.6	4.6	4.6	12.1
Operating lease obligations	36.0	7.0	8.3	6.1	4.6	3.8	6.2
Purchase obligations	3.2	3.2	—	—	—	—	—
Uncertain tax position obligations	4.4	4.4	—	—	—	—	—
Total contractual obligations	$ 1,326.5	$ 50.2	$ 77.2	$ 75.0	$ 73.5	$ 211.7	$ 838.9

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis.

The interest payable under the Partnership's credit facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates, which vary from time to time. However, given the same borrowing amount and rates in effect at March 31, 2012, the cash obligation for interest expense on the Partnership's credit facility would be approximately $4.4 million per year or $3.3 million for the remainder of 2012.

Indebtedness

As of March 31, 2012 and December 31, 2011, long-term debt consisted of the following (in millions):

	March 31, 2012	December 31, 2011
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at March 31, 2012 and December 31, 2011 was 3.16% and 2.9%, respectively	$ 139.0	$ 85.0
Senior unsecured notes (due 2018), net of discount of $11.1 million and $11.6 million, respectively, which bear interest at the rate of 8.875%	713.9	713.4
Debt classified as long-term	$ 852.9	$ 798.4

Credit Facility. On January 24, 2012, we amended our credit facility. This amendment increased our borrowing capacity from $485.0 million to $635.0 million and amended certain terms in the facility to provide additional financial flexibility during the remaining four-year term of the facility as described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness" in our Annual Report on Form 10-K for the year ended December 31, 2011.

As of March 31, 2012, our bank credit facility had a borrowing capacity of $635.0 million and there was $59.8 million in letters of credit issued and outstanding under the bank credit facility and $139.0 million of borrowings outstanding, leaving approximately $436.2 million available for future borrowing. The bank credit facility is guaranteed by substantially all of our subsidiaries. The bank credit facility matures in May 2016.

Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the three months ended March 31, 2012, and have determined that none would have a material impact to our Unaudited Condensed Consolidated Financial Statements.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements. Statements included in this report which are not historical facts are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "forecast," "may," "believe," "will," "expect," "anticipate," "estimate," "continue" or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. Such statements reflect our current views with respect to future events based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to specific uncertainties discussed elsewhere in this Form 10-Q, the risk factors set forth in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2011, and those set forth in Part II, "Item 1A. Risk Factors" of this report, if any, may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

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

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

On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank") into law, a part of which relates to increased regulation of the markets for derivative products of the type we use to manage areas of market risk. While the Commodity Futures Trading Commission has yet to issue complete final regulations to implement this increased regulation, Dodd-Frank may result in increased costs to us to implement our market risk management strategy.

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under three main types of contractual arrangements:

1. *Processing margin 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") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR. 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. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us, or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.

2. *Percent of liquids 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 liquids contracts, but do decline during periods of low NGL prices.

3. *Fee based contracts:* Under these contracts we have no commodity price exposure and are paid a fixed fee per unit of volume that is processed.

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Gas processing margins by contract types and gathering and transportation margins as a percent of total gross operating margin for the comparative year-to-date periods are as follows:

	Three Months Ended March 31, 2012	2011
Gathering and transportation margin	58.2%	55.7%
Gas processing margins:		
Processing margin	18.0%	17.9%
Percent of liquids	7.4%	12.2%
Fee based	16.4%	14.2%
Total gas processing	41.0%	44.3%
Total	100.0%	100.0%

We have hedges in place at March 31, 2012 covering a portion of the liquids volumes we expect to receive under percent of liquids (POL) contracts. The hedges were done via swaps and are set forth in the following table. The relevant payment index price is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

Period	Underlying	Notional Volume	We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)
April 2012 – December 2012	Ethane	13 (MBbls)	Index	$ 0.4850 /gal	$ (14)
April 2012 – December 2012	Propane	50 (MBbls)	Index	$ 1.2779 /gal	46
April 2012 – December 2012	Normal Butane	26 (MBbls)	Index	$ 1.7226 /gal	(191)
April 2012 – December 2012	Natural Gasoline	20 (MBbls)	Index	$ 2.3391 /gal	(39)
					$ (198)

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)
January 2013 – December 2013	Ethane	28 (MBbls)	Index	$ 0.4461 /gal	$ 24
January 2013 – December 2013	Propane	40 (MBbls)	Index	$ 1.2707 /gal	(29)
January 2013 – December 2013	Normal Butane	21 (MBbls)	Index	$ 1.7890 /gal	(38)
January 2013 – December 2013	Natural Gasoline	16 (MBbls)	Index	$ 2.2857 /gal	(14)
					$ (57)

*weighted average

We have hedged our exposure to declines in prices for NGL volumes produced for our account. The NGL volumes hedged, as set forth above, focus on our POL contracts. We hedge our POL exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total POL volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. We have hedged 39.0% of our hedgeable volumes at risk through December 2012 (21.2% of total volumes at risk through December 2012). We have also hedged 33.9% of our hedgeable volumes at risk for 2013 (20.9% of total volumes at risk for 2013).

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We also have hedges in place at March 31, 2012 covering the fractionation spread risk related to our processing margin contracts as set forth in the following tables:

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (In thousands)
April 2012–December 2012	Ethane	71 (MBbls)	Index	$ 0.6790 /gal*	$ 520
April 2012–December 2012	Propane	72 (MBbls)	Index	$ 1.3042 /gal*	145

April 2012–December 2012	Normal Butane	43 (MBbls)	Index	$ 1.7338 /gal*	(291)
April 2012–December 2012	Natural Gasoline	35 (MBbls)	Index	$ 2.2849 /gal*	(146)
April 2012–December 2012	Natural Gas	3,320 (MMBtu/d)	$ 4.6337 /MMBtu*	Index	(1,994)
					$ (1,766)

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (In thousands)
January 2013–December 2013	Propane	49 (MBbls)	Index	$ 1.3236 /gal*	$ 73
January 2013–December 2013	Normal Butane	29 (MBbls)	Index	$ 1.8653 /gal*	41
January 2013–December 2013	Natural Gasoline	23 (MBbls)	Index	$ 2.3217 /gal*	15
January 2013–December 2013	Natural Gas	1,370 (MMBtu/d)	$ 3.5605 /MMBtu*	Index	(51)
					$ 78

* weighted average

In relation to our fractionation spread risk, as set forth above, we have hedged 46.9% of our hedgeable liquids volumes at risk through December 31, 2012 (8.4% of total liquids volumes at risk) and 49.8% of the related hedgeable PTR volumes through December 31, 2012 (6.0% of total PTR volumes). We have also hedged 17.7% of our hedgeable liquids volumes at risk for 2013 (2.8% of total liquids volumes at risk) and 22.4% of the related hedgeable PTR volumes for 2013 (2.5% of total PTR volumes).

We are also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transport services. Approximately 3.0% 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.

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 natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural 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.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a risk management committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLs using 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.

As of March 31, 2012, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $3.5 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in an increase of approximately $3.0 million in the net fair value liability of these contracts as of March 31, 2012 to a net fair value liability of approximately $6.5 million.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At March 31, 2012, we had $139.0 million in borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $1.4 million for the year.

At March 31, 2012, we had total fixed rate debt obligations of $713.9 million, consisting of our senior unsecured notes with an interest rate of 8.875%. The fair value of this fixed rate obligation was approximately $771.2 million as of March 31, 2012. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of such debt by $24.1 million.

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 pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (March 31, 2012), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended March 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. ***Legal Proceedings***

We are 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 our financial position or results of operations.

For a discussion of certain litigation and similar proceedings, please refer to Note 8, "Commitments and Contingencies," of the Notes to Condensed Consolidated Financial Statements, which is incorporated by reference herein.

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

Information about risk factors for the three months ended March 31, 2012 does not differ materially from that set forth in Part I, Item 1A, of our Annual Report on Form 10-K for the year ended December 31, 2011 except as listed below.

Risks Related to the Clearfield Acquisition

We cannot assure you that we will complete the Clearfield Acquisition, or if completed, that such acquisition will be beneficial to us

We cannot assure you that we will complete the Clearfield Acquisition, or if completed, that such acquisition would achieve the desired benefits.

The Clearfield Acquisition would, if ultimately consummated, increase the size of our business and diversify the geographic areas in which we operate. In addition, if we complete the Clearfield Acquisition, failure to assimilate Clearfield's assets into our existing assets would adversely affect our financial condition and results of operations.

The Clearfield Acquisition would involve numerous risks, including the failure to realize expected profitability or growth and an increase in collateral demands by our counterparties. We will also be exposed to risks that are commonly associated with any acquisition, such as unanticipated liabilities and costs, some of which may be material, and diversion of management's attention. Moreover, Clearfield's operations are subject to similar stringent environmental laws and regulations relating to releases of pollutants into the environment and environmental protection as are our existing pipelines and facilities, and thus our operation of those new

assets would cause us to incur increased costs to maintain compliance with such laws and regulations. If we consummate the Clearfield Acquisition and if any of these risks or unanticipated liabilities or costs were to materialize, any desired benefits of the Clearfield Acquisition may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

If we complete the Clearfield Acquisition, we may face new risks as we enter new lines of business.

Clearfield conducts, among other things, crude, condensate and brine trucking and disposal operations and natural gas utility operations. Accordingly, if we complete the Clearfield Acquisition, we will enter into these new lines of business. We do not have prior experience in these lines of business and the success of the Clearfield Acquisition will be subject to all of the uncertainties regarding the maintenance and development of a new business. Although we intend to integrate Clearfield's products and services with ours, there can be no assurance regarding the successful integration and market acceptance of these new products and services. These activities can involve a number of uncertainties, risks and expenses, including the investment of significant time and resources, and we can give no assurance that our efforts will be successful.

If we complete the Clearfield Acquisition, we will expand our operations into new geographic areas.

Clearfield operates its business in geographic regions in which we do not currently operate, including Kentucky, Ohio and West Virginia. In order to operate effectively in these new regions, we will need to understand the local market and regulatory environment and identify and retain certain employees from Clearfield who are familiar with these markets. If we are not successful in retaining these employees or operating in these new geographic areas, we may not be able to compete effectively in the new markets or fully realize the expected benefits of the Acquisition.

If we complete the Clearfield Acquisition, a material portion of the income from our operations will flow up through subsidiaries taxed as corporations and such subsidiaries will pay substantial amounts of entity level taxes on such income.

The Clearfield Acquisition would, if ultimately consummated, be structured as an acquisition of the stock of Clearfield. Clearfield is taxed as a corporation for federal and state income tax purposes and has a very low tax basis in its assets. As a result, if the Clearfield Acquisition is ultimately consummated, (i) we will not be entitled to a tax basis step-up in Clearfield's assets (i.e., we would inherit Clearfield's low tax basis in its assets) and, thus, will not realize the benefit of any material amount of depreciation or amortization deductions with respect to Clearfield's assets, and (ii) a substantial portion of our income from operations will be reported by, and taxed to, subsidiaries that are taxable as corporations. Such subsidiaries are required to pay federal income tax on their income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates on their income. These entity level taxes are expected to be substantial which, in turn, will substantially reduce the cash available for distribution to our unitholders (as compared to the cash that would be available for distribution if Clearfield were not taxable as a corporation). Moreover, distributions from such subsidiaries will generally be taxed again to unitholders as corporate distributions, and none of the income, gains, losses, deductions or credits of such subsidiaries will flow through to our unitholders.

Additionally, because we will inherit Clearfield's low tax basis in its assets, if we were to subsequently sell such assets, we would recognize substantial amounts of taxable gain, and such gain would be reported by, and taxed to, subsidiaries taxable as corporations, as described in the preceding paragraph.

Recently proposed or finalized rules imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

On April 17, 2012, the U.S. Environmental Protection Agency ("EPA") approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. Moreover, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require a number of modifications to our natural gas exploration and production customer's as well as our operations including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our customers could result in reduced production by those customers and thus translate into reduced demand for our services.

In addition, federal agencies have recently initiated certain other regulatory initiatives or reviews of certain aspects of hydraulic fracturing that could further increase our natural gas exploration and production customer's costs and decrease their levels of production. On May 4, 2012, the federal Bureau of Land Management announced draft rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon Native American Indian and other federal lands. Moreover, in late 2011, the EPA announced that it is developing standards for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and indicated that such standards would be proposed by 2014. The adoption and implementation of one or both of these rules could further result in increased expenditures for our natural gas exploration and production customers or us, and could result in reduced demand for our services by these customers.

Note that the description of Crosstex's acquisition of Clearfield in the footnotes to the Form 10-Q and in MD&A in the Form 10-Q will define the terms "Clearfield" and "Clearfield Acquisition."

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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
2.1	—	Stock Purchase and Sale Agreement, dated as of May 7, 2012, by and among Energy Equity Partners, L.P., the Individual Owners (as defined therein), Clearfield Energy, Inc., Clearfield Holdings, Inc., West Virginia Oil Gathering Corporation, Appalachian Oil Purchasers, Inc., Kentucky Oil Gathering Corporation, Ohio Oil Gathering Corporation II, Ohio Oil Gathering Corporation III, OOGC Disposal Company I, M&B Gas Services, Inc., Clearfield Ohio Holdings, Inc., Pike Natural Gas Company, Eastern Natural Gas Company, Southeastern Natural Gas Company and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated May 7, 2012, filed with the Commission on May 8, 2012).***
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
3.3	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.4	—	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008).
3.5	—	Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
3.6	—	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).
3.7	—	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, file No. 000-50067).
3.8	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
3.10	—	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of January 19, 2010 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
4.1	—	Supplemental Indenture, dated as of January 24, 2012 and effective as of December 28, 2010, to the indenture governing the Issuers' 8.875% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantor named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 24, 2012, filed with the Commission on January 25, 2012).
10.1	—	Third Amendment to Amended and Restated Credit Agreement dated as of January 24, 2012, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 24, 2011, filed with the Commission on January 25, 2012).
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 the Principal Financial Officer of the Company pursuant to 18 U.S.C. Section 1350.
101**	—	The following financial information from Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations for the three months ended March 31, 2012 and 2011, (ii) Condensed Consolidated Balance Sheets as of March 31, 2012 and December 31, 2011, (iii) Consolidated Statements of Cash Flows for the three months ended March 31, 2012 and 2011, (iv) Consolidated Statements of Comprehensive Income for the three months ended March 31, 2012 and 2011, (v) Consolidated Statements of Changes in Partners' Equity for the quarter ended March 31, 2012, and (vi) the Notes to Condensed Consolidated Financial Statements.

*   Filed herewith.
** Furnished herewith.
*** Pursuant to Item 601(b)(2) of Regulation S-K, the Registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

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SIGNATURES

Pursuant to the requirements 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.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ MICHAEL J. GARBERDING
Michael J. Garberding
Senior Vice President and Chief Financial Officer

May 8, 2012

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy GP, LLC, 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 such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) 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 the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

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

/s/ BARRY E. DAVIS
BARRY E. DAVIS,
President and Chief Executive Officer
(principal executive officer)

Date: May 8, 2012

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, Senior Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, 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 such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) 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 the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

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

/s/ MICHAEL J. GARBERDING
MICHAEL J. GARBERDING,
Senior Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: May 8, 2012

Exhibit 32.1

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

In connection with the Quarterly Report of Crosstex Energy, L.P. (the “Registrant”) on Form 10-Q for the quarter ended March 31, 2012 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 Michael J. Garberding, 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 results of operations of the Registrant.

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

May 8, 2012

/s/ MICHAEL J. GARBERDING
Michael J. Garberding
Chief Financial Officer

May 8, 2012

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.