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 September 30, 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 October 29, 2012, the Registrant had 66,727,369 common units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	September 30, 2012 (Unaudited)	December 31, 2011
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,518	$ 24,143
Accounts receivable:		
Trade, net of allowance for bad debt of $428 and $405, respectively	75,067	22,680
Accrued revenue and other	121,293	143,115
Fair value of derivative assets	4,336	2,867
Natural gas and natural gas liquids, prepaid expenses and other	15,096	9,951
Assets held for disposition	22,822	—
Total current assets	241,132	202,756
Property and equipment, net of accumulated depreciation of $472,877 and $406,273, respectively	1,394,881	1,241,901
Fair value of derivative assets	750	—
Intangible assets, net of accumulated amortization of $242,205 and $199,248, respectively	446,105	451,462
Goodwill	150,630	—
Investment in limited liability company	88,761	35,000
Other assets, net	27,168	24,212
Total assets	$ 2,349,427	$ 1,955,331
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and other	$ 39,906	$ 22,550
Accrued gas and crude oil purchases	99,527	106,232
Fair value of derivative liabilities	860	5,587
Other current liabilities	58,504	66,065
Accrued interest	15,326	24,918
Liabilities held for disposition	2,261	—
Total current liabilities	216,384	225,352
Long-term debt	970,331	798,409
Other long-term liabilities	31,922	23,919
Deferred tax liability	74,516	7,192
Fair value of derivative liabilities	12	—
Commitments and contingencies	—	—
Partners' equity	1,056,262	900,459
Total liabilities and partners' equity	$ 2,349,427	$ 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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Unaudited) (In thousands, except per unit amounts)			
Revenues	$ 406,968	$ 517,498	$ 1,129,871	$ 1,533,003
Operating costs and expenses:				
Purchased gas, NGLs and crude oil	307,223	426,539	840,070	1,255,650
Operating expenses	35,551	28,126	93,928	81,083
General and administrative	16,470	13,712	44,398	38,111
(Gain) loss on sale of property	109	397	(395)	317
(Gain) loss on derivatives	759	563	(1,977)	5,520
Depreciation and amortization	45,059	31,912	110,107	93,200
Total operating costs and expenses	405,171	501,249	1,086,131	1,473,881
Operating income	1,797	16,249	43,740	59,122
Other income (expense):				
Interest expense, net of interest income	(23,229)	(19,507)	(63,932)	(59,952)
Equity in earnings of limited liability company	1,511	—	1,511	—
Other income	4,439	786	4,464	656
Total other expense	(17,279)	(18,721)	(57,957)	(59,296)
Loss before non-controlling interest and income taxes	(15,482)	(2,472)	(14,217)	(174)

Income tax provision	(672)	(287)	(1,507)	(898)
Net loss	(16,154)	(2,759)	(15,724)	(1,072)
Less: Net loss attributable to the non- controlling interest	(54)	(23)	(163)	(130)
Net loss attributable to Crosstex Energy, L.P.	$ (16,100)	$ (2,736)	$ (15,561)	$ (942)
Preferred interest in net loss attributable to Crosstex Energy, L.P.	$ 5,640	$ 4,558	$ 15,346	$ 13,382
General partner interest in net loss	$ (309)	$ (76)	$ (420)	$ (709)
Limited partners' interest in net loss attributable to Crosstex Energy, L.P.	$ (21,431)	$ (7,218)	$ (30,487)	$ (13,615)
Net loss attributable to Crosstex Energy, L.P. per limited partners' unit:				
Basic and diluted per common unit	$ (0.34)	$ (0.14)	$ (0.53)	$ (0.26)

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Loss

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Unaudited) (In thousands)			
Net loss	$ (16,154)	$ (2,759)	$ (15,724)	$ (1,072)
Hedging (gains) losses reclassified to earnings	(593)	421	(168)	1,510
Adjustment in fair value of derivatives	(179)	335	1,578	(1,200)
Comprehensive loss	(16,926)	(2,003)	(14,314)	(762)
Comprehensive loss attributable to non-controlling interest	54	23	163	130
Comprehensive loss attributable to Crosstex Energy, L.P.	$ (16,872)	$ (1,980)	$ (14,151)	$ (632)

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Nine Months Ended September 30, 2012

	Common Units		Preferred Units		General Partner Interest		Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units			
					(Unaudited) (In thousands)				
Balance, December 31, 2011	$ 730,010	50,677	$ 147,770	14,706	$ 20,322	1,334	$ (503)	$ 2,860	$ 900,459
Issuance of common units	232,791	15,780	—	—	3,362	207	—	—	236,153
Proceeds from exercise of unit options	347	70	—	—	—	—	—	—	347
Conversion of restricted units for common units, net of units withheld for taxes	(1,030)	188	—	—	—	—	—	—	(1,030)
Capital contributions	—	—	—	—	98	5	—	—	98
Stock-based compensation	3,973	—	—	—	3,523	—	—	—	7,496
Distributions	(54,155)	—	(14,412)	—	(4,324)	—	—	(56)	(72,947)
Net income (loss)	(30,487)	—	15,346	—	(420)	—	—	(163)	(15,724)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	(168)	—	(168)
Adjustment in fair value of derivatives	—	—	—	—	—	—	1,578	—	1,578
Balance, September 30, 2012	$ 881,449	66,715	$ 148,704	14,706	$ 22,561	1,546	$ 907	$ 2,641	$ 1,056,262

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net loss	$ (15,724)	$ (1,072)
Adjustments to reconcile net loss to net cash provided by operating activities, net of assets acquired or liabilities assumed:		
Depreciation and amortization	110,107	93,200
(Gain) loss on sale of property and other assets	(3,381)	317
Deferred tax benefit	(375)	(375)
Non-cash stock-based compensation	7,496	5,504

Non-cash portion of derivatives (gain) loss	(5,523)	165
Amortization of debt issue costs	3,940	5,278
Amortization of discount on notes	1,423	1,423
Equity in earnings of limited liability company	(1,511)	—
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	(18,431)	30,115
Natural gas and natural gas liquids, prepaid expenses and other	(7,144)	(3,493)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	(26,296)	(47,181)
Net cash provided by operating activities	44,581	83,881
Cash flows from investing activities:		
Additions to property and equipment	(141,319)	(62,829)
Acquisition of business	(212,521)	—
Proceeds from sale of property	11,677	425
Investment in limited liability company	(52,250)	(35,000)
Net cash used in investing activities	(394,413)	(97,404)
Cash flows from financing activities:		
Proceeds from borrowings	696,500	390,250
Payments on borrowings	(526,000)	(322,308)
Payments on capital lease obligations	(2,337)	(2,254)
Increase (decrease) in drafts payable	4,319	(103)
Debt refinancing costs	(6,896)	(3,936)
Conversion of restricted units, net of units withheld for taxes	(1,030)	(1,798)
Issuance of common units	232,791	—
Distribution to partners	(72,947)	(59,135)
Proceeds from exercise of unit options	347	513
Contributions from general partner	3,460	159
Net cash provided by financing activities	328,207	1,388
Net decrease in cash and cash equivalents	(21,625)	(12,135)
Cash and cash equivalents, beginning of period	24,143	17,697
Cash and cash equivalents, end of period	$ 2,518	$ 5,562
Cash paid for interest	$ 70,460	$ 70,074
Cash paid for income taxes	$ 953	$ 905

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

September 30, 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 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 provides a variety of crude services throughout the Ohio River Valley (ORV) which include crude oil gathering via pipelines and trucks and oilfield brine disposal. 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 (the "General Partner") 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. In 2012, the Partnership made an additional capital contribution of $52.3 million to HEP related to HEP's acquisition of substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas. HEP owns midstream assets and provides midstream and construction services to Eagle Ford Shale producers. The Partnership owns 30.6 percent of HEP and accounts for this investment under the equity method of accounting. This investment is reflected on the balance sheet as "Investment in limited liability company." The Partnership's proportional share of earnings is recorded as an increase to this investment account and recorded as equity in earnings of limited liability company.

(c) Potential Change 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 Sabine plant. The primary term of the contract expired in March 2012 and is currently renewed on a month-to-month basis. The Partnership anticipates that operations will cease in early 2013 because it is likely that this third-party fractionation agreement will be terminated. During the three months ended September 30, 2012, the Partnership revised the useful life of these assets and began accelerating depreciation and amortization for the estimated non-recoverable costs associated with the plant totaling $26.4 million. Depreciation and amortization expense for the three months ended September 30, 2012 includes $8.8 million associated with such non-recoverable costs, and the Partnership will recognize additional depreciation and amortization expense of $8.8 million in the fourth quarter of 2012 and the first quarter of 2013. The net book value for the plant, excluding these non-recoverable costs, is $19.0 million as of September 30, 2012. 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.

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(2) Acquisition

On July 2, 2012, the Partnership, through a wholly-owned subsidiary, completed its previously announced acquisition of all of the issued and outstanding common stock of Clearfield Energy, Inc. and Clearfield Energy's wholly-owned subsidiaries (collectively, "Clearfield"). 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. All of these assets are included in the Partnership's ORV segment.

The Partnership paid approximately $212.5 million in cash (before working capital and certain purchase price adjustments) for the acquisition and the purchase was funded with proceeds from the senior notes offering in May 2012.

Included in the Clearfield acquisition were three local distributions companies, or LDCs, which the Partnership marketed for sale and were classified as held for disposition on the balance sheet as of September 30, 2012. The Partnership chose not to apply discontinued operations presentation on the income statement as the related amounts are immaterial. On October 15, 2012, the Partnership entered into an agreement to sell the LDCs for an amount of $19.5 million. The assets held for disposition are recorded at the sales price of $19.5 million.

The goodwill recognized from the Clearfield acquisition results primarily from the value of opportunity created from the strategic asset positioning in the Utica and Marcellus shale plays which provides the Partnership with a substantial growth platform in a new geographic area.

The Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 20 years.

The Partnership assumed a long-term liability related to additional benefit obligations. Also, the Partnership assumed a long-term liability related to inactive easement commitments for a period of 10 years.

The Partnership formed a wholly-owned corporate entity to acquire the common stock of Clearfield and assumed the carryover basis of the Clearfield assets. The difference between our purchase price for the Clearfield assets and the carryover tax basis for such assets resulted in the recognition of a deferred tax liability of $67.7 million. This deferred liability is expected to become payable no later than 2027.

Purchase Price Allocation in Clearfield Acquisition

Based on currently available information, the following table is a summary of the consideration paid for the Clearfield acquisition and the preliminary purchase price allocation for the fair value of the assets acquired and liabilities assumed at the acquisition date:

Purchase Price Allocation (in thousands):		
Purchase Price to Clearfield Energy, Inc.	$	212,521
Total purchase price	$	212,521
Assets acquired:		
Current assets	$	15,466
Assets held for disposition		19,500
Property, plant, and equipment		93,671
Goodwill		150,630
Intangibles		37,600
Liabilities assumed:		
Current liabilities		(23,575)
Liabilities held for disposition		(2,642)
Deferred taxes		(67,700)
Long term liabilities		(10,429)
Total purchase price	$	212,521

For the period from July 2, 2012 to September 30, 2012, the Partnership recognized $52.9 million of crude oil buy/sell, crude oil transportation and brine disposal sales related to properties acquired in the Clearfield acquisition. For the period from July 2, 2012 to September 30, 2012, the Partnership recognized $46.1 million net operating expense related to properties acquired in the Clearfield acquisition.

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Pro Forma Information

The following unaudited pro forma condensed financial data for the nine months ended September 30, 2012 and three and nine months ended September 30, 2011 gives effect to the Clearfield acquisition as if it had occurred on January 1, 2011. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

	Three Months Ended	Nine Months Ended	
	September 30, 2011	September 30, 2012	September 30, 2011
Pro forma total revenues	$ 564,198	$ 1,235,782	$ 1,676,004
Pro forma net loss	$ (6,067)	$ (18,005)	$ (9,330)
Pro forma net loss attributable to Crosstex Energy, L.P.	$ (6,043)	$ (17,842)	$ (9,200)
Pro forma net loss per common unit:			
Basic and Diluted	$ (0.12)	$ (0.32)	$ (0.18)

(3) Long-Term Debt

As of September 30, 2012 and December 31, 2011, long-term debt consisted of the following (in thousands):

	September 30, 2012	December 31, 2011
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at September 30, 2012 and December 31, 2011 was 4.75% and 2.9%, respectively	$ 5,500	$ 85,000
Senior unsecured notes (due 2018), net of discount of $10.2 million and $11.6 million, respectively, which bear interest at the rate of 8.875%	714,831	713,409
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250,000	—
Debt classified as long-term	$ 970,331	$ 798,409

Credit Facility. As of September 30, 2012, there was $61.6 million in outstanding letters of credit and $5.5 million borrowed under the Partnership's bank credit facility, leaving approximately $567.9 million available for future borrowing based on the borrowing capacity of $635.0 million.

In January 2012, the Partnership further amended its credit facility to increase the Partnership's borrowing capacity from $485.0 million to $635.0 million and amend certain terms under the facility to provide additional financial flexibility during the remaining four-year term of the facility.

The Partnership amended the credit facility again in May 2012. This amendment, among other things, (i) increased the maximum permitted consolidated leverage ratio (as defined in the amended credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) during the Clearfield acquisition period (as defined in the amended credit facility, being generally the four quarterly measurement periods after closing the Clearfield acquisition) from 5.0 to 1.0 to 5.5 to 1.0, and (ii) increased the maximum permitted consolidated leverage ratio during any other acquisition period (as defined in the amended credit facility, being generally the three quarterly measurement periods after closing certain material acquisitions) from 5.0 to 1.0 to 5.5 to 1.0.

In August 2012, the Partnership amended the credit facility to include projected EBITDA from material projects (as defined in the amendment, but generally being the construction or expansion of any capital project by the Partnership or any of its subsidiaries that is expected to cost more than $20.0 million and the Partnership's "Riverside Phase II" project) in its EBITDA for purposes of calculating compliance with the amended credit agreement's minimum interest coverage ratio, maximum leverage ratio and maximum senior leverage ratio. The amount of projected EBITDA from material projects that is included in such financial covenant calculations is subject to the approval of Bank of America, N.A. (the "Administrative Agent"), and it will be based on contracts related to the material project, expected expenses, the completion percentage of the material project, the expected commercial operation date of the material project, and other factors deemed appropriate by the Administrative Agent. The aggregate amount of all material project EBITDA adjustments during any period shall be limited to 15% of the total actual consolidated EBITDA for such period (which total actual consolidated EBITDA shall be determined without including any material project EBITDA adjustments).

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, crude gathering and transportation assets, brine disposal 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 other 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.

2022 Notes. On May 24, 2012, the Partnership issued $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments are due semi-annually in arrears in June and December. Net proceeds from the sale of the notes of $245.1 million (net of transaction costs) were used to fund the Clearfield acquisition and for general partnership purposes, including capital expenditures for the Cajun-Sibon natural gas liquids pipeline expansion.

The Partnership may redeem up to 35% of the 2022 Notes at any time prior to June 1, 2015 in an amount not greater than the cash proceeds from equity offerings at a redemption price of 107.125% of the principal amount of the 2022 Notes (plus accrued and unpaid interest to the redemption date).

Prior to June 1, 2017, the Partnership may redeem all or a part of the 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date.

On or after June 1, 2017, the Partnership may redeem all or a part of the 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Under the terms of the indenture governing the 2022 Notes agreement, repurchase offer obligations would be triggered by a change of control combined with a ratings decline on the notes.

Non-Guarantors. All 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 and nine months ended September 30, 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 nine months ended September 30, 2012 and 2011 as these amounts are not considered material.

Condensed Consolidating Balance Sheets
September 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 227,012	$ 14,120	$ —	$ 241,132
Property, plant and equipment, net	1,189,183	205,698	—	1,394,881
Total other assets	713,414	—	—	713,414
Total assets	$ 2,129,609	$ 219,818	$ —	$ 2,349,427
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 209,899	$ 6,485	$ —	$ 216,384
Long-term debt	970,331	—	—	970,331
Other long-term liabilities	106,450	—	—	106,450
Partners' capital	842,929	213,333	—	1,056,262
Total liabilities & partners' capital	$ 2,129,609	$ 219,818	$ —	$ 2,349,427

December 31, 2011

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
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 September 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 392,085	$ 20,468	$ (5,585)	$ 406,968
Total operating costs and expenses	(400,897)	(9,859)	5,585	(405,171)
Operating income (loss)	(8,812)	10,609	—	1,797
Interest expense, net	(23,220)	(9)	—	(23,229)
Other income	5,950	—	—	5,950
Income (loss) from continuing operations before non-controlling interest and income taxes	(26,082)	10,600	—	(15,482)
Income tax provision	(665)	(7)	—	(672)
Net loss attributable to non-controlling interest	—	54	—	54
Net income (loss) attributable to Crosstex Energy, L.P.	$ (26,747)	$ 10,647	$ —	$ (16,100)

Notes to Condensed Consolidated Financial Statements-(Continued)

For the Three Months Ended September 30, 2011

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 501,866	$ 21,287	$ (5,655)	$ 517,498
Total operating costs and expenses	(497,149)	(9,755)	5,655	(501,249)
Operating income	4,717	11,532	—	16,249
Interest expense, net	(19,507)	—	—	(19,507)
Other expense	786	—	—	786
Income (loss) from continuing operations before non-controlling interest and income taxes	(14,004)	11,532	—	(2,472)
Income tax provision	(283)	(4)	—	(287)
Net income attributable to non-controlling interest	—	23	—	23
Net (loss) income attributable to Crosstex Energy, L.P.	$ (14,287)	$ 11,551	$ —	$ (2,736)

For the Nine Months Ended September 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 1,086,065	$ 64,946	$ (21,140)	$ 1,129,871
Total operating costs and expenses	(1,078,556)	(28,715)	21,140	(1,086,131)
Operating income	7,509	36,231	—	43,740
Interest expense, net	(63,867)	(65)	—	(63,932)
Other income	5,975	—	—	5,975
Income (loss) from continuing operations before non-controlling interest and income taxes	(50,383)	36,166	—	(14,217)
Income tax provision	(1,493)	(14)	—	(1,507)
Net loss attributable to non-controlling interest	—	163	—	163
Net income (loss) attributable to Crosstex Energy, L.P.	$ (51,876)	$ 36,315	$ —	$ (15,561)

For the Nine Months Ended September 30, 2011

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,487,910	$ 65,148	$ (20,055)	$ 1,533,003
Total operating costs and expenses	(1,464,720)	(29,216)	20,055	(1,473,881)
Operating income	23,190	35,932	—	59,122
Interest expense, net	(59,952)	—	—	(59,952)
Other expense	656	—	—	656
Income (loss) from continuing operations before non-controlling interest and income taxes	(36,106)	35,932	—	(174)
Income tax provision	(886)	(12)	—	(898)
Net loss attributable to non-controlling interest	—	130	—	130
Net (loss) income attributable to Crosstex Energy, L.P.	$ (36,992)	$ 36,050	$ —	$ (942)

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

Condensed Consolidating Statements of Cash Flow
For the Nine Months Ended September 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Net cash flows provided by (used in) operating activities	$ (3,335)	$ 47,916	$ —	$ 44,581
Net cash flows used in investing activities	$ (393,866)	$ (547)	$ —	$ (394,413)
Net cash flows provided by (used in) financing activities	$ 328,206	$ (46,989)	$ 46,989	$ 328,206

For the Nine Months Ended September 30, 2011

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Net cash flows provided by operating activities	$ 35,676	$ 48,205	$ —	$ 83,881
Net cash flows used in investing activities	$ (95,202)	$ (2,202)	$ —	$ (97,404)
Net cash flows provided by (used in) financing activities	$ 1,388	$ (45,274)	$ 45,274	$ 1,388

(4) 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 September 30, 2012 are summarized as follows (in thousands):

Compressor equipment	$	37,199
Less: Accumulated amortization		(12,950)
Net assets under capital leases	$	24,249

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 September 30, 2012 (in thousands):

2012	$	1,146
2013 through 2016 ($4,582 annually)		18,328
Thereafter		12,100
Less: Interest		(5,525)
Net minimum lease payments under capital lease		26,049
Less: Current portion of net minimum lease payments		(4,448)
Long-term portion of net minimum lease payments	$	21,601

Other long-term liabilities also include an inactive easement commitment of $7.1 million (net of discount of $2.9 million) assumed with the Clearfield acquisition which is due over the next 10 years as such easements are utilized and a long-term liability of $3.2 million assumed with the Clearfield acquisition for consulting services from the affiliate of the seller which is payable in monthly installments of $0.08 million over the next 5 years with a contract cancellation option by the affiliate of the seller in July 2014 that would cause the remaining liability to be payable at such time.

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(5) Partners' Capital

(a) Issuance of Common Units

On May 15, 2012, we issued 10,120,000 common units representing limited partner interests in the Partnership at a public offering price of $16.28 per unit for net proceeds of $158.0 million. In addition, Crosstex Energy GP, LLC made a general partner contribution of $3.4 million in connection with the issuance to maintain its 2% general partner interest. The net proceeds from the common units offering were used for general partnership purposes.

On September 14, 2012, we issued 5,660,378 common units representing limited partner interests in the Partnership at a private offering price of $13.25 per unit for net proceeds of $74.8 million. The net proceeds from the common units issuance were used primarily to fund the Partnership's currently identified projects, including the Cajun-Sibon NGL pipeline expansion, and for general partnership purposes. Crosstex Energy GP, LLC did not make a general partner contribution to maintain its 2% general partner interest as discussed in the "Amendment to Partnership Agreement" section below.

(b) Amendment to Partnership Agreement

On September 13, 2012, the board of directors of the General Partner amended the Partnership Agreement to (i) convert the General Partner's obligation to make capital contributions to the Partnership to maintain its 2% interest in connection with the issuance of additional limited partner interests by the Partnership to an option of the General Partner to make future capital contributions to maintain its then current general partner percentage interest and (ii) amend certain terms and conditions of the Series A Convertible Preferred Units (the "Preferred Units"), including, among other corresponding modifications, the following amendments:

· Distributions Paid-In-Kind (PIK): for each quarter through the quarter ending December 31, 2013 (the "PIK Period"), the Partnership will pay distributions in-kind on the Preferred Units ("PIK Preferred Units") without penalty and without affecting the Partnership's ability to pay cash distributions on the common units.

· PIK Preferred Unit Price: during the PIK Period, the fixed price used to determine the number of PIK Preferred Units to be paid instead of cash distributions will increase from $8.50 per Preferred Unit to $13.25 per Preferred Unit.

· Optional Redemption: the existing right of the holders of Preferred Units to convert the Preferred Units into common units was modified so that such right may not be exercised until the earlier of (i) the business day following the record date for the distribution for the quarter ending December 31, 2013 and (ii) February 10, 2014.

· Mandatory Redemption: the right of the Partnership to convert the Preferred Units into common units on January 19, 2013 was modified so that such right may not be exercised until the business day following the distribution for the quarter ending December 31, 2013 (subject to the satisfaction of the existing conditions applicable to such right).

(c) Cash Distributions

Unless restricted by the terms of the Partnership's credit facility and/or the indentures governing our 2022 Notes and our 8 7/8% senior unsecured notes due 2018 ("2018 Notes" and, together with the 2022 Notes, "all senior unsecured notes"), 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.

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The Partnership's first quarter and second quarter 2012 distributions on its common and preferred units of $0.33 per unit were paid on May 15, 2012 and August 14, 2012, respectively. The Partnership declared its third quarter 2012 distribution on its common and preferred units of $0.33 per unit to be paid on November 14, 2012.

(d) Earnings per Unit and Dilution Computations

The Partnership had common units and Preferred Units outstanding during the three and nine months ended September 30, 2012 and September 30, 2011.

The Preferred Units are entitled to a quarterly distribution paid-in-kind 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. The fair value of the PIK Preferred Unit distributions will be based on the market value of common units on the record date of such distributions.

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Limited partners' interest in net loss	$ (21,431)	$ (7,218)	$ (30,487)	$ (13,615)
Distributed earnings allocated to:				
Common units (1)(2)	$ 20,948	$ 15,705	$ 55,752	$ 46,020
Unvested restricted units (1)(2)	310	298	1,008	883
Total distributed earnings	$ 21,258	$ 16,003	$ 56,760	$ 46,903
Undistributed loss allocated to:				
Common units	$ (41,977)	$ (22,808)	$ (85,676)	$ (59,411)
Unvested restricted units	(712)	(413)	(1,571)	(1,107)
Total undistributed loss	$ (42,689)	$ (23,221)	$ (87,247)	$ (60,518)
Net loss allocated to:				
Common units	$ (21,029)	$ (7,103)	$ (29,924)	$ (13,393)
Unvested restricted units	(402)	(115)	(563)	(222)
Total limited partners' interest in net loss	$ (21,431)	$ (7,218)	$ (30,487)	$ (13,615)
Basic and diluted net loss per unit:				
Basic and diluted common unit	$ (0.34)	$ (0.14)	$ (0.53)	$ (0.26)

(1) Three months ended September 30, 2012 represents a declared distribution of $0.33 per unit payable on November 14, 2012. Nine months ended September 30, 2012 represents distributions paid of $0.66 per unit and distributions declared of $0.33 payable November 14, 2012.
(2) Three months ended September 30, 2011 represents a declared distribution of $0.31 per unit paid on November 11, 2011. Nine months ended September 30, 2011 represents distributions paid of $0.60 per unit and distributions declared of $0.31 paid November 11, 2011.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2012 and 2011 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Basic and diluted weighted average units outstanding:				
Weighted average limited partner common units outstanding	62,027	50,650	56,315	50,562

All common unit equivalents were antidilutive in the three and nine months ended September 30, 2012 and September 30, 2011 because the limited partners were allocated net losses in these periods.

The general partner is entitled to a distribution in relation to its percentage interest with respect to all distributions made to common unitholders. If the distributions are in excess of $0.2125 per unit, distributions are made 100.0% to the common and preferred unitholders minus the general partner's percentage interest, 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 the percentage interest 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 the general partner's percentage interest 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Income allocation for incentive distributions	$ 1,157	$ 600	$ 3,266	$ 1,597
Stock-based compensation attributable to CEI's restricted shares	(1,166)	(634)	(3,443)	(2,334)
General partner interest in net income (loss)	(300)	(42)	(243)	28
General partner share of net loss	$ (309)	$ (76)	$ (420)	$ (709)

(6) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership accounts for share-based compensation in accordance with FASB ASC 718, which requires 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Cost of share-based compensation charged to general and administrative expense	$ 2,193	$ 1,304	$ 6,546	$ 4,569
Cost of share-based compensation charged to operating expense	310	205	950	935
Total amount charged to income	$ 2,503	$ 1,509	$ 7,496	$ 5,504

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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 nine months ended September 30, 2012 is provided below:

	Nine Months Ended September 30, 2012	
Crosstex Energy, L.P. Restricted Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	949,844	$ 10.45
Granted	371,600	16.81
Vested*	(261,768)	7.87
Forfeited	(41,617)	15.02
Non-vested, end of period	1,018,059	$ 13.24
Aggregate intrinsic value, end of period (in thousands)	$ 15,678	

* Vested units include 63,512 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 September 30, 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 and nine months ended September 30, 2012 and 2011 are provided below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Crosstex Energy, L.P. Restricted Units:	2012	2011	2012	2011
Aggregate intrinsic value of units vested	$ 448	$ 329	$ 4,031	$ 6,438
Fair value of units vested	$ 452	$ 389	$ 2,060	$ 5,945

As of September 30, 2012, there was $6.3 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted-average period of 1.4 years.

(c) Unit Options

A summary of the unit option activity for the nine months ended September 30, 2012 is provided below:

	Nine Months Ended September 30, 2012	
Crosstex Energy, L.P. Unit Options:	**Number of Units**	**Weighted Average Exercise Price**
Outstanding, beginning of period	451,574	$ 6.99
Exercised	(69,773)	5.03
Forfeited	(11,281)	15.58
Outstanding, end of period	370,520	$ 7.11
Options exercisable at end of period	304,799	
Weighted average contractual term (years) end of period:		
Options outstanding	6.4	
Options exercisable	6.2	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 3,513	
Options exercisable	$ 2,896	

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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 and nine months ended September 30, 2012 and September 30, 2011 are provided below (in thousands):

Crosstex Energy, L.P. Unit Options:	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Intrinsic value of unit options exercised	$ 327	$ 348	$ 805	$ 1,333
Fair value of unit options vested	$ —	$ 1	$ 277	$ 562

As of September 30, 2012, there was $0.1 million of unrecognized compensation cost related to non-vested unit options. The cost is expected to be recognized over a weighted average period of 0.3 years.

(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 nine months ended September 30, 2012 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Nine Months Ended September 30, 2012 Number of Shares	Nine Months Ended September 30, 2012 Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,221,351	$ 7.40
Granted	476,451	13.27
Vested*	(282,494)	6.07
Forfeited	(57,162)	11.01
Non-vested, end of period	1,358,146	$ 9.59
Aggregate intrinsic value, end of period (in thousands)	$ 19,055	

* Vested shares include 62,546 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 September 30, 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 and nine months ended September 30, 2012 and September 30, 2011 are provided below (in thousands):

Crosstex Energy, Inc. Restricted Shares:	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Aggregate intrinsic value of shares vested	$ 537	$ 226	$ 3,963	$ 3,915
Fair value of shares vested	$ 448	$ 342	$ 1,714	$ 5,623

As of September 30, 2012 there was $6.3 million of unrecognized compensation cost related to CEI restricted shares for directors, officers and employees. The cost is expected to be recognized over a weighted average period of 1.4 years.

(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 September 30, 2012.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Change in fair value of derivatives that do not qualify for hedge accounting	$ 433	$ (619)	$ (5,481)	$ 111
Realized losses on derivatives	308	1,227	3,547	5,355
Ineffective portion of derivatives qualifying for hedge accounting	18	(45)	(43)	(127)
Net (gains) losses related to commodity swaps	$ 759	$ 563	$ (1,977)	$ 5,339
Put option premium mark to market	—	—	—	181
(Gains) losses on derivatives	$ 759	$ 563	$ (1,977)	$ 5,520

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

	September 30, 2012	December 31, 2011
Fair value of derivative assets — current, designated	$ 888	$ 151
Fair value of derivative assets — current, non-designated	3,448	2,716
Fair value of derivative assets — long term, designated	54	—
Fair value of derivative assets — long term, non-designated	696	—
Fair value of derivative liabilities — current, designated	(29)	(702)
Fair value of derivative liabilities — current, non-designated	(831)	(4,885)
Fair value of derivative liabilities — long term, designated	(11)	—
Fair value of derivative liabilities — long term, non-designated	(1)	—
Net fair value of derivatives	$ 4,214	$ (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 September 30, 2012 (all gas volumes are expressed in MMBtus and liquids volumes are expressed in gallons). The remaining term of the contracts extend no later than December 2013 for derivatives. Changes in the fair value of the

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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	September 30, 2012 Volume	Fair Value
	(In thousands)	
*Cash Flow Hedges:**		
Liquids swaps (short contracts)	(8,000)	$ 902
Total swaps designated as cash flow hedges		$ 902
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	186	$ (1)
Physical offsets to swing swap transactions (short contracts)	(186)	—
Swing swaps (short contracts)	(620)	(3)
Physical offsets to swing swap transactions (long contracts)	620	—
Basis swaps (long contracts)	775	(28)
Physical offsets to basis swap transactions (short contracts)	(775)	2,071
Basis swaps (short contracts)	(775)	23
Physical offsets to basis swap transactions (long contracts)	775	(2,233)
Processing margin hedges — liquids (short contracts)	(8,791)	2,453
Processing margin hedges — gas (long contracts)	1,167	(285)
Processing margin hedges — gas (short contracts)	(161)	147
Liquids swaps - non-designated (short contracts)	(4,393)	1,126
Storage swap transactions — gas (short contracts)	(300)	(77)
Storage swap transactions — liquids inventory (long contracts)	630	17
Storage swap transactions — liquids inventory (short contracts)	(1,470)	102
Total mark to market derivatives		$ 3,312

* All are gas contracts, volume in MMBtus, 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 (ISDAs) with its counterparties. If the Partnership's counterparties failed to perform under existing swap contracts entered into under these ISDAs, the Partnership's maximum loss as of September 30, 2012 of $5.7 million would be reduced to $5.1 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

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 September 30,		Nine Months Ended September 30,	
Increase (Decrease) in Midstream Revenue	**2012**	**2011**	**2012**	**2011**
Liquids realized gain (loss) included in Midstream revenue	$ 456	$ (527)	$ 851	$ (2,235)

Natural Gas

As of September 30, 2012, the Partnership had no balances in accumulated other comprehensive income related to natural gas.

Liquids

As of September 30, 2012, an unrealized derivative fair value net gain of $0.9 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income. Of that amount, a net gain of $0.8 million is expected to be reclassified into earnings through September 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**
September 30, 2012.	$ 2,617	$ 695	$ —	$ 3,312

(8) 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):

	September 30, 2012 Level 2	December 31, 2011 Level 2
Commodity Swaps*	$ 4,214	$ (2,720)
Total	$ 4,214	$ (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 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):

	September 30, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 970,331	$ 1,035,033	$ 798,409	$ 882,500
Obligations under capital lease	$ 26,049	$ 28,668	$ 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 $5.5 million in borrowings under its revolving credit facility included in long-term debt as of September 30, 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 September 30, 2012 and December 31, 2011, the Partnership also had borrowings totaling $714.8 million and $713.4 million, net of discount, respectively, under the 2018 Notes with a fixed rate of 8.875% and borrowings of $250.0 million as of September 30, 2012 under the 2022 Notes with a fixed rate of 7.125%. The fair value of all senior unsecured notes as of September 30, 2012 and December 31, 2011 was based on Level 1 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

(9) 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. To date, 23 of the 25 sites requiring remediation have been completed and have received a "No Further Action" status from the Louisiana Department of Environmental Quality. The remaining two sites continuing with remediation efforts are expected to reach closure in 2013. 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 submitted the claim to its insurance carriers and vigorously defended the lawsuit. Insurers for the Partnership recently reached a confidential settlement of this matter, at no cost to the Partnership.

At times, the Partnership's gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. 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 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 has appealed the matter and has posted a bond to secure the judgment pending its resolution. The Partnership has accrued $2.0 million related to this matter 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.

(10) 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), the south Louisiana processing and NGL assets (PNGL) and rail, truck, pipeline, and barge facilities in the Ohio River Valley (ORV). Operating activity for intersegment eliminations is shown in the corporate segment.

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.

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CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

	LIG	NTX	PNGL	ORV	Corporate	Totals
			(In thousands)			
Three Months Ended September 30, 2012:						
Sales to external customers	$ 141,977	$ 65,606	$ 146,448	$ 52,937	$ —	$ 406,968
Sales to affiliates	$ 50,304	$ 22,278	$ 35,209	$ —	$ (107,791)	$ —
Purchased gas, NGLs and crude oil	$ (166,374)	$ (41,807)	$ (166,288)	$ (40,545)	$ 107,791	$ (307,223)
Operating expenses	$ (8,468)	$ (14,255)	$ (7,306)	$ (5,522)	$ —	$ (35,551)
Segment profit	$ 17,439	$ 31,822	$ 8,063	$ 6,870	$ —	$ 64,194
Gain (loss) on derivatives	$ (498)	$ (293)	$ 32	$ —	$ —	$ (759)
Depreciation, amortization and impairments	$ (4,360)	$ (21,508)	$ (16,503)	$ (2,164)	$ (524)	$ (45,059)
Capital expenditures	$ 1,596	$ 7,596	$ 34,064	$ 556	$ 5,573	$ 49,385
Identifiable assets	$ 280,959	$ 1,067,591	$ 538,427	$ 318,258	$ 144,192	$ 2,349,427
Three Months Ended September 30, 2011:						
Sales to external customers	$ 200,161	$ 83,684	$ 233,653	$ —	$ —	$ 517,498
Sales to affiliates	22,059	26,755	82	—	(48,896)	—
Purchased gas, NGLs and crude oil	(189,393)	(67,041)	(219,001)	—	48,896	(426,539)
Operating expenses	(8,944)	(11,957)	(7,225)	—	—	(28,126)
Segment profit	$ 23,883	$ 31,441	$ 7,509	$ —	$ —	$ 62,833
Gain (loss) on derivatives	$ (509)	$ (225)	$ 171	$ —	$ —	$ (563)
Depreciation, amortization and impairments	$ (3,198)	$ (19,861)	$ (7,859)	$ —	$ (994)	$ (31,912)
Capital expenditures	$ 58	$ 8,205	$ 3,362	$ —	$ 660	$ 12,285
Identifiable assets	$ 303,900	$ 1,092,754	$ 475,580	$ —	$ 72,092	$ 1,944,326
Nine Months Ended September 30, 2012:						
Sales to external customers	$ 410,154	$ 191,523	$ 475,257	$ 52,937	$ —	$ 1,129,871
Sales to affiliates	183,529	$ 70,988	$ 120,997	$ —	$ (375,514)	$ —
Purchased gas, NGLs and crude oil	(509,196)	$ (123,284)	$ (542,559)	$ (40,545)	$ 375,514	$ (840,070)
Operating expenses	(25,164)	$ (41,549)	$ (21,693)	$ (5,522)	$ —	$ (93,928)
Segment profit	$ 59,323	$ 97,678	$ 32,002	$ 6,870	$ —	$ 195,873
Gain (loss) on derivatives	$ 4,145	$ (2,709)	$ 541	$ —	$ —	$ 1,977
Depreciation, amortization and impairments	$ (10,695)	$ (62,950)	$ (32,530)	$ (2,164)	$ (1,768)	$ (110,107)
Capital expenditures	$ 3,484	$ 41,050	$ 79,981	$ 556	$ 7,109	$ 132,180
Identifiable assets	$ 280,959	$ 1,067,591	$ 538,427	$ 318,258	$ 144,192	$ 2,349,427
Nine Months Ended September 30, 2011:						
Sales to external customers	$ 624,558	$ 252,462	$ 655,983	$ —	$ —	$ 1,533,003
Sales to affiliates	68,110	69,635	773	—	(138,518)	—
Purchased gas, NGLs and crude oil	(596,313)	(194,560)	(603,295)	—	138,518	(1,255,650)
Operating expenses	(25,912)	(35,417)	(19,754)	—	—	(81,083)
Segment profit	$ 70,443	$ 92,120	$ 33,707	$ —	$ —	$ 196,270
Gain (loss) on derivatives	$ (4,463)	$ (1,319)	$ 262	$ —	$ —	$ (5,520)
Depreciation, amortization and impairments	$ (10,366)	$ (56,325)	$ (23,400)	$ —	$ (3,109)	$ (93,200)
Capital expenditures	$ 2,738	$ 43,216	$ 12,998	$ —	$ 1,862	$ 60,814
Identifiable assets	$ 303,900	$ 1,092,754	$ 475,580	$ —	$ 72,092	$ 1,944,326

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Segment profits	$ 64,194	$ 62,833	$ 195,873	$ 196,270
General and administrative expenses	(16,470)	(13,712)	(44,398)	(38,111)
Gain (loss) on derivatives	(759)	(563)	1,977	(5,520)
Gain (loss) on sale of property	(109)	(397)	395	(317)
Depreciation, amortization and impairments	(45,059)	(31,912)	(110,107)	(93,200)
Operating income	$ 1,797	$ 16,249	$ 43,740	$ 59,122

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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, natural gas liquids (NGLs) and crude oil. We also have rail, truck, pipeline and barge facilities for natural gas, NGLs and crude oil. Additionally, we provide crude oil, condensate and brine water services. All of the activities are managed 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) which includes our presence in the Permian Basin, the Ohio River Valley (ORV) through the Clearfield acquisition described below, 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). We also have access to 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, NGLs and crude oil for a margin, or to gather, process, transport or market natural gas, NGLs and crude oil for a fee. We earn a volume based fee for providing crude oil transporation and brine disposal services. We define gross operating margin as operating revenue minus cost of purchased gas, NGLs and crude oil. 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, the volumes of crude oil handled at our crude terminals, the volumes of crude oil gathered, transported, purchased and sold and brine disposed. We generate revenues from seven 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;
- purchasing and reselling crude oil;
- providing crude oil transportation and terminal services; and
- providing brine disposal 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. Additionally, we provide crude oil, condensate and brine water services on a volume basis. 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 $13.1 million during the nine months ended September 30, 2012 on the Delivery Contract. We currently expect that we will record an additional loss of approximately $4.5 million to $5.0 million on the Delivery Contract for the remainder of the year ending December 31, 2012 and a loss of $18 million to $21 million during the year ended December 31, 2013. This estimate is based on forward prices, basis spreads and other market assumptions as of September 30, 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 generally gather or transport crude oil owned by others by rail, truck, pipeline and barge facilities for a fee, orwe buy crude oil from a producer at a fixed discount to a market index, then transport and resell the crude oil at the market index. We execute all purchases and sales substantially currently, thereby establishing the basis for the margin we will receive for each crude oil transaction. Additionally, we provide crude oil, condensate and brine water services on a volume basis.

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, fees, services, and other transaction costs related to acquisitions, 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. In January 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.

We amended the credit facility again in May 2012. This amendment, among other things, (i) increased the maximum permitted consolidated leverage ratio (as defined in the amended credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) during the Clearfield acquisition period (as defined in the amended credit facility, being generally the four quarterly measurement periods after closing the Clearfield acquisition) from 5.0 to 1.0 to 5.5 to 1.0, and (ii) increased the maximum permitted consolidated leverage ratio during any other acquisition period (as defined in the amended credit facility, being generally the three quarterly measurement periods after closing certain material acquisitions) from 5.0 to 1.0 to 5.5 to 1.0.

In August 2012, we further amended the credit facility to include projected EBITDA from material projects (as defined in the amendment, but generally being the construction or expansion of any capital project by us or any of our subsidiaries that is expected to cost more than $20.0 million and our "Riverside Phase II" project) in its EBITDA for purposes of calculating compliance with the amended credit agreement's minimum interest coverage ratio, maximum leverage ratio and maximum senior leverage ratio. The amount of projected EBITDA from material projects that is included in such financial covenant calculations is subject to approval of Bank of America, N.A. (the "Administrative Agent"), and it will be based on contracts related to the material project, expected expenses, the completion percentage of the material project, the expected commercial operation date of the material project, and other factors deemed appropriate by the Administrative Agent, all as more fully set forth in the credit agreement amendment. The aggregate amount of all material project EBITDA adjustments during any period shall be limited to 15% of the total actual consolidated EBITDA for such period (which total actual consolidated EBITDA shall be determined without including any material project EBITDA adjustments).

2022 Notes. On May 24, 2012, we issued $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments are due semi-annually in arrears in June and December. Net proceeds from the sale of the notes of $245.1 million (net of transaction costs) were used to fund the Clearfield acquisition and for general partnership purposes, including capital expenditures for the Cajun-Sibon NGL pipeline expansion.

Issuance of Common Units. On May 15, 2012, we issued 10,120,000 common units representing limited partner interests in the Partnership at a public offering price of $16.28 per unit for net proceeds of $158.0 million. In addition, Crosstex Energy GP, LLC made a general partner contribution of $3.4 million in connection with the issuance to maintain its 2% general partner interest. The net proceeds from the common unit offering were used for general partnership purposes.

On September 14, 2012, we issued 5,660,378 common units representing limited partner interests in the Partnership at a private offering price of $13.25 per unit for net proceeds of $74.8 million. The net proceeds from the common units issuance were used primarily to fund the Partnership's currently identified projects, including the Cajun-Sibon NGL pipeline expansion, and for general partnership purposes. Crosstex Energy GP, LLC did not make a general partner contribution to maintain its 2% general partner interest as discussed in the "Amendment to Partnership Agreement" section below.

Amendment to Partnership Agreement. On September 13, 2012, the board of directors of our General Partner amended the Partnership Agreement to (i) convert the General Partner's obligation to make capital contributions to the Partnership to maintain its 2% interest in connection with the issuance of additional limited partner interests by the Partnership to an option of the General Partner to make future capital contributions to maintain its then current general partner percentage interest and (ii) amend certain terms and conditions of the Series A Convertible Preferred Units (the "Preferred Units"), including, among other corresponding modifications, the following amendments:

- Distributions Paid-In-Kind (PIK): for each quarter through the quarter ending December 31, 2013 (the "PIK Period"), the Partnership will pay distributions in-kind on the Preferred Units ("PIK Preferred Units") without penalty and without affecting the Partnership's ability to pay cash distributions on the common units.

- PIK Preferred Unit Price: during the PIK Period, the fixed price used to determine the number of PIK Preferred Units to be paid instead of cash distributions will increase from $8.50 per Preferred Unit to $13.25 per Preferred Unit.

- Optional Redemption: the existing right of the holders of Preferred Units to convert the Preferred Units into common units was modified so that such right may not be exercised until the earlier of (i) the business day following the record date for the distribution for the quarter ending December 31, 2013 and (ii) February 10, 2014.

- Mandatory Redemption: the right of the Partnership to convert the Preferred Units into common units on January 19, 2013 was modified so that such right may not be exercised until the business day following the distribution for the quarter ending December 31, 2013 (subject to the satisfaction of the existing conditions applicable to such right).

Investment in Limited Liability Company. On June 22, 2011, we entered into a limited liability agreement with HEP for an initial capital contribution of $35.0 million in exchange for an individual ownership interest in HEP. In 2012, we made an additional capital contribution of $52.3 million to HEP related to HEP's acquisition of substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas. HEP owns midstream assets and provides midstream and construction services to Eagle Ford Shale producers. We own 30.6 percent of HEP and account for this investment under the equity method of accounting. This investment is reflected on the balance sheet as "Investment in limited liability company." The Partnership's proportional share of earnings is recorded as an increase to this investment account.

Clearfield Acquisition. On July 2, 2012, we completed the acquisition of all of the issued and outstanding common stock of Clearfield Energy, Inc. and Clearfield Energy's wholly-owned subsidiaries (collectively, "Clearfield"). Clearfield is a crude oil, condensate and water services company with operations in Ohio, Kentucky and West Virginia.

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, and approximately 200 miles of crude oil pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage, seven existing brine water disposal wells with one under development and an extensive fleet of trucks. In addition, Clearfield owns more than 2,500 miles of unused rights' of way.

We paid approximately $212.5 million in cash for the acquisition and the acquisition was funded from restricted cash that resulted from the 2022 Notes offering. The assets associated with this acquisition are included in a new reporting segment that is referred to as Ohio River Valley.

Cajun Sibon I. We have completed our commercial contracting for Phase I of our Cajun-Sibon NGL extension and Eunice fractionator expansion. With contracts for third-party volumes in excess of 60,000 barrels per day and our equity volumes, we expect to begin operations at the project's initial capacity of 70,000 barrels per day.

We have commenced commercial construction of the pipeline extension and expect that Phase I facilities will be operational in the third quarter of 2013. The capital cost for the Phase I project is approximately $270.0 million. The pipeline extension and fractionation expansion allow us to provide gas producers and midstream companies an improved NGL transportation, fractionation and marketing alternative to Mont Belvieu.

Riverside Fractionation Facility Expansion. On May 7, 2012, we announced our plans to increase our capacity to transload crude oil from rail cars to both barges and pipeline at our 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 began in late June 2012 and is expected be operational in the second quarter of 2013. The expansion project is expected to cost approximately $16.4 million. We have entered into a long-term agreement, which supports the expansion.

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.

We define adjusted EBITDA as net income plus interest expense, provision for income taxes, depreciation and amortization expense, impairments, stock-based compensation, costs related to acquisitions, (gain) loss on noncash derivatives, and minority interest; less gain on sale of property and equity in earnings of limited liability company. 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.

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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 material projects and 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 net loss to adjusted EBITDA:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(In millions)			
Net loss attributable to Crosstex Energy, L.P.	$ (16.1)	$ (2.7)	$ (15.6)	$ (0.9)
Interest expense	23.2	19.5	63.9	60.0
Depreciation and amortization	45.1	31.9	110.1	93.2
Equity in earnings of limited liability company	(1.5)	—	(1.5)	—
(Gain) loss on sale of property	0.1	0.4	(0.4)	0.3
Stock-based compensation	2.5	1.5	7.5	5.5
Other (a)	1.9	(0.5)	(1.7)	1.3
Adjusted EBITDA	$ 55.2	$ 50.1	$ 162.3	$ 159.4

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

We define gross operating margin, generally, as revenues minus cost of purchased gas, NGLs, and crude. 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 and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil 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 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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(In millions)			
Total gross operating margin	$ 99.8	$ 91.0	$ 289.8	$ 277.3
Add (deduct):				
Operating expenses	(35.6)	(28.1)	(93.9)	(81.1)

General and administrative expenses	(16.5)	(13.7)	(44.4)	(38.1)
Gain (loss) on sale of property	(0.1)	(0.4)	0.4	(0.3)
Gain (loss) on derivatives	(0.8)	(0.6)	1.9	(5.5)
Depreciation and amortization	(45.0)	(31.9)	(110.1)	(93.2)
Operating income	$ 1.8	$ 16.3	$ 43.7	$ 59.1

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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, NGLs and crude oil as reflected in the table below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Dollars in millions)			
LIG Segment				
Revenues	$ 192.3	$ 222.2	$ 593.7	$ 692.7
Purchased gas and NGLs	(166.4)	(189.4)	(509.2)	(596.3)
Total gross operating margin	$ 25.9	$ 32.8	$ 84.5	$ 96.4
NTX Segment				
Revenues	$ 87.9	$ 110.4	$ 262.5	$ 322.1
Purchased gas and NGLs	(41.8)	(67.0)	(123.3)	(194.6)
Total gross operating margin	$ 46.1	$ 43.4	$ 139.2	$ 127.5
PNGL Segment				
Revenues	$ 181.7	$ 233.8	$ 596.3	$ 656.7
Purchased gas and NGLs	(166.3)	(219.0)	(542.6)	(603.3)
Total gross operating margin	$ 15.4	$ 14.8	$ 53.7	$ 53.4
ORV Segment				
Revenues	$ 52.9	—	$ 52.9	—
Purchased crude oil	(40.5)	—	(40.5)	—
Total gross operating margin	$ 12.4	—	$ 12.4	—
Corporate				
Revenues	$ (107.8)	$ (48.9)	$ (375.5)	$ (138.5)
Purchased gas and NGLs	107.8	48.9	375.5	138.5
Total gross operating margin	$ —	$ —	$ —	$ —
Total				
Revenues	$ 407.0	$ 517.5	$ 1,129.9	$ 1,533.0
Purchased gas, NGLs and crude oil	(307.2)	(426.5)	(840.1)	(1,255.7)
Total gross operating margin	$ 99.8	$ 91.0	$ 289.8	$ 277.3
Midstream Volumes:				
LIG				
Gathering and Transportation (MMBtu/d)	741,000	859,000	814,000	907,000
Processing (MMBtu/d)	215,000	236,000	241,000	244,000
NTX				
Gathering and Transportation (MMBtu/d)	1,163,000	1,121,000	1,177,000	1,120,000
Processing (MMBtu/d)	386,000	258,000	353,000	248,000
PNGL				
Processing (MMBtu/d)	602,000	699,000	769,000	837,000
NGL Fractionation (Gals/d)	1,350,000	987,000	1,284,000	1,088,000
ORV*				
Crude Oil Handling (Bbls/d) (1)	12,000	—	12,000	—
Brine Disposal (Bbls/d) (1)	8,000	—	8,000	—

* Crude oil handling from PNGL is included in ORV reported volumes
(1) Crude oil handling and brine disposal volume include a daily average for July 2012, August 2012, and September 2012, the three-month period these assets were operated by us.

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Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Gross Operating Margin. Gross operating margin was $99.8 million for thethree months ended September 30, 2012 compared to $91.0 million for the three months ended September 30, 2011, an increase of $8.8 million, or 9.7%. The overall increase was due to the July 2012 acquisition of the ORV assets, increased throughput on our Permian Basin systems, increase in NGL fractionation and marketing activity, and an increase from our south Louisiana crude oil terminal activity. The following provides additional details regarding this change in gross operating margin:

- The ORV segment is comprised of the assets that were purchased from Clearfield Energy, Inc. in July 2012. These assets contributed a total increase of $12.4 million to our gross operating margin growth for the three months ended September 30, 2012. Gross operating margins from crude oil and condensate handling and brine water disposal and handling were $8.5 million and $3.9 million, respectively. Further details on the acquisition and the assets are discussed more fully under the section "Recent Developments."

- The NTX segment had gross operating margin increase of $2.7 million for the three months ended September 30, 2012 compared to the three months ended September

30, 2011. The gas processing facilities located in the Permian Basin, which commenced operation during the first quarter of 2012, contributed $3.2 million to gross operating margin. The north Texas processing plants also had a gross operating margin increase of $0.3 million. Throughput volumes on the gathering and transmission assets contributed $0.4 million to gross margin. These increases were partially offset by an increase in losses of $1.2 million on the delivery contract discussed more fully under "Overview."

- The PNGL segment had a gross operating margin increase of $0.6 million for the three months ended September 30, 2012 compared to the three months ended September 30, 2011. Our NGL fractionation and marketing activities contributed $3.8 million of the gross operating margin increase due to increased NGL volumes from truck and rail activity at both of our Eunice and Riverside fractionators. These increases were largely offset by a combined gross operating margin decrease of $4.9 million from our south Louisiana processing plants due to the less favorable processing environment during 2012 as compared to 2011. The PNGL segment also includes our new crude oil terminal activity in south Louisiana which contributed $1.7 million to our gross operating margin during the three months ended September 30, 2012.

- The LIG segment had a decrease in gross operating margin of $6.9 million for the three months ended September 30, 2012 compared to the three months ended September 30, 2011. The majority of the decrease is attributed to a weaker processing environment coupled with lower volumes due to scheduled maintenance on our Gibson plant during the third quarter of 2012. Gross operating margins decreased by $4.5 million from our Gibson and Plaquemine plants and decreased by $1.7 million from gas processed for our account by a third-party processor. Gross operating margins decreased by $0.8 million on the gathering and transmission assets due to decrease in throughput volumes primarily due to an impact of the Bayou Corne sinkhole discussed more fully under "Changes in Operations During 2012 and 2013."

Operating Expenses. Operating expenses were $35.6 million for the three months ended September 30, 2012 compared to $28.1 million for the three months ended September 30, 2011, an increase of $7.4 million, or 26.4%. This increase in operating expenses includes a total increase of $5.5 million related to the direct operating costs of the ORV assets acquired from Clearfield in July 2012. The primary contributors to the total increase are as follows:

- our labor and benefits expense increased by $4.3 million related to the acquisition of our ORV assets and 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;
- our materials, supplies and contractor cost increased by $1.1 million related to the acquisition of our ORV assets and compressor overhauls;
- our rents, lease and vehicle expense increased by $1.3 million related to the acquisition of our ORV assets partially offset by a reduction of $0.6 million in compressor rental cost;
- our training, audit and consulting cost related to regulatory activity increased by $0.3 million; and
- our ad valorem tax expense increased by $0.5 million due to project expansions.

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General and Administrative Expenses. General and administrative expenses were $16.5 million for the three months ended September 30, 2012 compared to $13.7 million for the three months ended September 30, 2011, an increase of $2.8 million, or 20.1%. The increase is primarily due to the following:

- our salaries, wages and benefits increased by $1.1 million due to an increase in headcount;
- our bad debt expense decreased by $1.0 million;
- our stock based compensation expense increased by $0.9 million; and
- our fees and services increased by $1.3 million related to our acquisition of our ORV assets and the associated closing and due diligence costs.

Gain/Loss on Derivatives. We had a loss on derivatives of $0.8 million for the three months ended September 30, 2012 compared to a loss of $0.6 million for the three months ended September 30, 2011. The derivative transaction types contributing to the net loss are as follows (in millions):

	Three Months Ended September 30,			
	2012		2011	
	Total	Realized	Total	Realized
Basis swaps	$ 0.1	$ 1.3	$ (0.2)	$ (0.2)
Processing margin hedges	0.3	(0.8)	0.6	1.3
Other	0.4	(0.2)	0.2	0.1
Net losses related to commodity swaps	$ 0.8	$ 0.3	$ 0.6	$ 1.2

Depreciation and Amortization. Depreciation and amortization expenses were $45.1 million for the three months ended September 30, 2012 compared to $31.9 million for the three months ended September 30, 2011, an increase of $13.1 million, or 41.2%. The increase includes $8.0 million due to accelerated depreciation of the Sabine Plant with total depreciation related to Sabine being $8.8 million for the quarter ended 2012, $0.4 million for the abandoned LIG pipe associated with the Bayou Corne sinkhole and $0.7 million related to another section of abandoned pipe. In addition, there was an increase of $3.6 million due to net asset additions including $2.2 million related to the acquisition of the ORV assets. This increase also includes $0.4 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.

Interest Expense. Interest expense was $23.2 million for the three months ended September 30, 2012 compared to $19.5 million for the three months ended September 30, 2011, an increase of $3.7 million, or 19.1%. Net interest expense consists of the following (in millions):

	Three Months Ended September 30,	
	2012	2011
Senior notes	$ 21.0	$ 16.6
Bank credit facility	1.4	1.4
Amortization of debt issue costs	1.4	1.2
Other	(0.6)	0.3
Total	$ 23.2	$ 19.5

Equity in earnings of limited liability company. Equity in earnings of limited liability company was $1.5 million for the three months ended September 30, 2012 compared to no equity in earnings of limited liability company for the three months ended September 30, 2011. The increase of $1.5 million of equity in earnings relates to our HEP equity investment.

Other Income. Other income was $4.4 million for the three months ended September 30, 2012 compared to $0.8 million for the three months ended September 30, 2011. Our 2012 other income includes a $3.0 million net gain related to the assignment to a third party of our rights, title and interest in a contract for the construction of a processing plant. In addition, we settled certain liabilities associated with sold assets for less than the accrued liabilities resulting in a $1.3 million gain.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Gross Operating Margin. Gross operating margin was $289.8 million for the nine months ended September 30, 2012 compared to $277.3 million for the nine months ended September 30, 2011, an increase of $12.5 million, or 4.5%. The overall increase was due to the July 2012 acquisition of the ORV assets, increased throughput on our NTX and Permian Basin systems, an increase in NGL fractionation and marketing activity and an increase from our south Louisiana crude oil terminal activity. The following provides additional details regarding this change in gross operating margin:

- The ORV segment is comprised of the assets that were purchased from Clearfield Energy, Inc. in July 2012. These assets contributed a total increase of $12.4 million to our gross operating margin growth for the nine months ended September 30, 2012. Gross operating margins from crude oil and condensate handling and brine water disposal and handling were $8.5 million and $3.9 million, respectively. Further details on the acquisition and the assets are discussed more fully under the section "Recent Developments."

- The NTX segment had a gross operating margin increase of $11.7 million for the nine months ended September 30, 2012 compared to the nine months ended September 30, 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 $6.6 million. The north Texas processing plants also had a gross operating margin increase of $3.0 million for the comparable periods primarily due to increased supply due to our expansion projects. In addition, the gas processing facilities located in the Permian Basin, which commenced operations in 2012, contributed $5.8 million to gross operating margin. These increases were partially offset by an increase in losses of $3.7 million on the delivery contract discussed more fully under "Overview."

- The PNGL segment had a increase in gross operating margin of $0.3 million for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. Our NGL fractionation and marketing activities contributed a gross operating margin improvement of $5.9 million as a result of the growth and expansion of our NGL fractionation and marketing activities. We have increased our NGL fractionation and marketing activities through the restart of the Eunice fractionator in June 2011 and by increasing our truck and rail activity at our Riverside fractionator. These increases were substantially offset by a combined gross operating margin decrease of $9.3 million from processing activities at our south Louisiana processing plants due to a less favorable processing environment during 2012 as compared to 2011. The PNGL segment also includes our new crude oil terminal activity in south Louisiana which contributed $3.6 million of our gross operating margin during the nine months ended September 30, 2012.

- The LIG segment had a decrease in gross operating margin of $11.9 million for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. The weaker processing environment during 2012 as compared to 2011 contributed to a decline in gross operating margins for processing activities during the nine months ended September 30, 2012. Gross operating margins decreased by $4.8 million from our Plaquemine and Gibson plants and decreased by $7.0 million from gas processed for our account by a third-party processor.

Operating Expenses. Operating expenses were $93.9 million for the nine months ended September 30, 2012 compared to $81.1 million for the nine months ended September 30, 2011, an increase of $12.8 million, or 15.8%. This increase in operating expenses includes a total increase of $5.5 million related to the direct operating costs of the ORV assets acquired from Clearfield in July 2012. The primary contributors to the total increase are as follows:

- our labor and benefits expense increased by $6.7 million related to the acquisition of our ORV assets and an increase in employee headcount for activities related to project expansions in the North Texas segment, including the Permian Basin processing facilities, and the PNGL segment, which was partially offset by a $1.4 million reduction in bonus expense;
- our materials, supplies and contractor cost increased by $3.4 million related to compressor overhauls, maintenance cost and the acquisition of our ORV assets;
- our rents, lease and vehicle expense increased by $1.3 million related to the acquisition of our ORV assets and offset by a reduction of $1.1 million for savings on compressor rental cost;
- our training, audit, and consulting cost related to regulatory activity increased by $0.5 million;
- our utilities, fees and services increased by $1.5 million related to litigation costs and project expansion activities; and
- our ad valorem tax expense increased by $1.4 million due to project expansions.

General and Administrative Expenses. General and administrative expenses were $44.4 million for the nine months ended September 30, 2012 compared to $38.1 million for the nine months ended September 30, 2011, an increase of $6.3 million, or 16.5%. The increase is primarily a result of the following:

- our salaries, wages, and benefits increased by $2.9 million due to an increase in headcount partially offset by a decrease of $2.4 million in bonus expense;
- our stock based compensation expense increased by $2.0 million; and
- our fees and services increased by $3.9 million related to legal and other professional fees of which $2.8 million relates to our recent acquisition of our ORV assets.

Gain/Loss on Derivatives. Gain on derivatives was $2.0 million for the nine months ended September 30, 2012 compared to a loss of $5.5 million for the nine months ended September 30, 2011. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Nine Months Ended September 30,			
	2012		2011	
	Total	Realized	Total	Realized
Basis swaps	$ 3.5	$ 3.5	$ 0.8	$ 0.9
Processing margin hedges	(3.9)	0.8	4.5	4.5
Other	(1.6)	(0.8)	0.2	—
Net (gains) losses related to commodity swaps	$ (2.0)	$ 3.5	$ 5.5	$ 5.4

Depreciation and Amortization. Depreciation and amortization expenses were $110.1 million for the nine months ended September 30, 2012 compared to $93.2 million for the nine months ended September 30, 2011, an increase of $16.9 million, or 18.1%. The increase includes $8.0 million due to accelerated depreciation of the Sabine Plant with total depreciation related to Sabine being $8.8 million for the quarter ended 2012, $0.4 million for the abandoned LIG pipe associated with the Bayou Corne sinkhole and $0.7 million related to another section of abandoned pipe. In addition, depreciation and amortization increased $4.0 million due to net asset additions including $2.2 million related to the acquisition of the ORV assets. The increase also includes $3.8 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.

Interest Expense. Interest expense was $63.9 million for the nine months ended September 30, 2012 compared to $60.0 million for the nine months ended September 30, 2011. Net interest expense consists of the following (in millions):

Nine Months Ended

	September 30, 2012		September 30, 2011	
Senior notes	$	56.0	$	49.7
Bank credit facility		5.2		4.0
Amortization and write off of debt issue costs		3.9		5.3
Other		(1.2)		1.0
Total	$	63.9	$	60.0

Equity in earnings of limited liability company. Equity in earnings of limited liability company was $1.5 million for the nine months ended September 30, 2012 compared to no equity in earnings of limited liability company for the nine months ended September 30, 2011. The increase of $1.5 million of equity in earnings relates to our HEP equity investment.

Other Income. Other income was $4.5 million for the nine months ended September 30, 2012 compared to $0.7 million for the nine months ended September 30, 2011. Our 2012 other income includes a $3.0 million net gain related to the assignment to a third party of our rights, title and interest in a contract for the construction of a processing plant. In addition, we settled certain liabilities associated with sold assets for less than the accrued liabilities resulting in a $1.3 million gain.

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 $44.6 million for the nine months ended September 30, 2012 compared to net cash provided by operating activities of $83.9 million for nine months ended September 30, 2011. Income before non-cash income and expenses and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
Income before non-cash income and expenses	$	96.5	$	104.4
Changes in working capital	$	(51.9)	$	(20.6)

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The decrease in cash flow from income before non-cash income and expenses of $7.9 million resulted from an increase in operating and general and administrative expenses offset by an increase in gross operating margin from nine months ended September 30, 2012 compared to nine months ended September 30, 2011.

The change in working capital for 2012 and 2011 primarily relates to normal fluctuations in trade receivable and payable balances due to timing of collections and payments.

Cash Flows from Investing Activities. Net cash used in investing activities was $394.4 million for the nine months ended September 30, 2012 and $97.4 million for the nine months ended September 30, 2011. Our primary investing outflows were acquisition costs and capital expenditures, net of accrued amounts, as follows (in millions):

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
Growth capital expenditures	$	130.5	$	53.4
Maintenance capital expenditures		10.8		9.4
Acquisition		212.5		—
Investment in limited liability company		52.3		35.0
Total	$	406.1	$	97.8

Cash Flows from Financing Activities. Net cash provided by financing activities was $328.2 million for the nine months ended September 30, 2012 and $1.4 million for the nine months ended September 30, 2011. Our primary financing activities consist of the following (in millions):

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
Net (repayments) borrowings on bank credit facility	$	(79.5)	$	75.0
2022 Notes borrowings		250.0		—
Series B senior secured note repayment		—		(7.1)
Net repayments under capital lease obligations		(2.3)		(2.3)
Debt refinancing costs		(6.9)		(3.9)
Common unit offerings		232.8		—

Distributions to unitholders and our general partner also*represent* a primary use of cash in financing activities. Total cash distributions made during the nine months ended September 30, 2012 and 2011 were as follows (in millions):

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
Common units	$	54.2	$	44.2
Preferred units		14.4		12.6
General partner interest (including incentive distribution rights)		4.3		2.3
Total	$	72.9	$	59.1

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 credit facility. We borrow money under our credit facility to fund checks as they are presented. As of September 30, 2012, we had approximately $567.9 million of available borrowing capacity under our credit facility. Changes in drafts payable for the nine months ended September 30, 2012 and 2011 were as follows (in millions):

	Nine Months Ended September 30,	
	2012	2011
(Decrease) increase in drafts payable	$ 4.3	$ (0.1)

Changes in Operations During 2012 and 2013. Currently, the Partnership's Sabine plant has a contract with a third-party to fractionate the raw-make NGLs produced by the Sabine plant. The primary term of the contract expired March 2012 and is currently renewed on a month-to-month basis. The Partnership anticipates that operations will cease in early 2013 because it is likely that this third-party fractionation agreement will be terminated. During the three months ended September 30, 2012, the Partnership began accelerating depreciation and amortization for the estimated non-recoverable costs associated with the plant totaling $26.4 million. Depreciation and amortization expense for the three months ended September 30, 2012 includes $8.8 million associated with such non-recoverable costs, and the Partnership will recognize additional depreciation and amortization expense of $8.8 million in the fourth quarter of 2012 and the first quarter of 2013. The net book value for the plant, excluding these non-recoverable costs, is $19.0 million as of September 30, 2012. 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 Partnership had a gas gathering contract with a major producer in our North Texas assets with a primary term that expired August 31, 2012 that was modified to be on a month-to-month basis beginning September 1, 2012. Subsequently, the modified contract was extended for six months at a reduced gathering fee rate which will reduce our gross operating margin by approximately $1.2 million per quarter. We are in the process of negotiating a longer term agreement.

In early August 2012, a slurry-filled sinkhole developed in Assumption Parish near Bayou Corne, Louisiana. The cause of the slurry is currently under investigation by Louisiana state and local officials. Consequently, we took a section of our 36-inch-diameter natural gas pipeline located near the sinkhole out of service. Service to certain markets, primarily in the Mississippi River area, has been curtailed or interrupted, and we have worked with our customers to secure alternative natural gas supplies so that disruptions are minimized. We expect that the ongoing overall business impact on the services provided by the pipeline, which include gathering, processing, transportation and end-user sales, will be approximately $0.25-$0.3 million per month while the pipeline section is out of service.

We will relocate the portion of the pipeline affected and certain services will not resume until the relocation has been completed. We are evaluating potential rerouting alternatives, timing and expected costs. Based on the current alternatives being considered, we estimate the cost of the relocation to be $20.0 to $25.0 million and expect to complete the relocation by summer 2013. We are assessing the potential for recovering our losses from responsible parties and insurance coverage. We have accelerated the depreciation of this effected portion of the existing pipeline in the amount of $0.4 million and will capitalize the costs of the replacement pipeline.

Capital Requirements. During the nine months ended September 30, 2012, capital investments were $395.3 million (including $52.3 million related to HEP and $212.5 million related to the Clearfield acquisition), which were funded by internally generated cash flow, borrowings under our credit facility, equity offerings and the issuance of senior unsecured notes. Our remaining 2012 budgeted capital spend for growth capital includes approximately $124.6 million related to project and acquisition expenditures of which $91.4 million relates to the Cajun-Sibon NGL pipeline expansion. We expect to fund the growth capital expenditures from the proceeds of borrowing under our bank credit facility and from other debt and equity sources.

Off-Balance Sheet Arrangements. No off-balance sheet arrangements existed as of September 30, 2012.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of September 30, 2012 is as follows (in millions):

	Payments Due by Period						
	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt obligations	$ 975.0	$ —	$ —	$ —	$ —	$ —	$ 975.0
Bank credit facility	5.5	—	—	—	—	5.5	—
Interest payable on fixed long-term debt obligations	531.6	9.3	82.2	82.2	82.2	82.2	193.5
Capital lease obligations	31.6	1.1	4.6	4.6	4.6	4.6	12.1
Operating lease obligations	46.8	1.7	8.4	7.5	7.6	6.9	14.7
Purchase obligations	8.6	8.6	—	—	—	—	—
Consulting agreement	4.7	0.3	1.0	3.4	—	—	—
Inactive easement commitment*	10.0	—	—	—	—	—	10.0
Uncertain tax position obligations	4.7	4.7	—	—	—	—	—
Total contractual obligations	$ 1,618.5	$ 25.7	$ 96.2	$ 97.7	$ 94.4	$ 99.2	$ 1,205.3

* Amounts related to inactive easements due as utilized by the Partnership with balance due at end of 10 years if not utilized.

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 September 30, 2012, the cash obligation for interest expense on the Partnership's credit facility would be approximately $0.3 million per year or less than $0.1 million for the remainder of 2012.

Indebtedness

As of September 30, 2012 and December 31, 2011, long-term debt consisted of the following (in millions):

	September 30, 2012	December 31, 2011
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at September 30, 2012 and December 31, 2011 was 4.75% and 2.9%, respectively	$ 5.5	$ 85.0

Senior unsecured notes (due 2018), net of discount of $10.2 million and $11.6 million, respectively, which bear interest at the rate of 8.875%	714.8	713.4
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250.0	—
Debt classified as long-term	$ 970.3	$ 798.4

Credit Facility. In January 2012, May 2012 and August 2012, we amended our credit facility. For further discussion of these amendments, please refer to Part I, "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations — Recent Developments."

As of September 30, 2012, there was $61.6 million in outstanding letters of credit and $5.5 million borrowed under the Partnership's bank credit facility, leaving approximately $567.9 million available for future borrowing based on the borrowing capacity of $635.0 million. The credit facility is guaranteed by substantially all of our subsidiaries. The credit facility matures in May 2016.

Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the nine months ended September 30, 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.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodity Futures Trading Commission (the "CFTC") to regulate certain markets for over-the-counter ("OTC") derivative products. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives to clear through clearinghouses. We may be affected by the cost of margin requirements and of certain clearing and trade-execution requirements in connection with our derivatives activities. The CFTC has adopted regulations that may provide to us the certainty that we will not be required to comply directly with margin requirements or clearing requirements. The rules could also impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations, including determinations with respect to the applicability of margin requirements and other trading structures, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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.

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

Three Months Ended September 30,	Nine Months Ended September 30,

	2012	2011	2012	2011
Gathering, transportation and crude handling margin	70.0 %	61.2 %	63.6 %	60.0 %
Gas processing margins:				
Processing margin	4.9 %	17.9 %	11.2 %	16.6 %
Percent of liquids	6.4 %	7.9 %	8.1 %	10.4 %
Fee based	18.7 %	13.0 %	17.1 %	13.0 %
Total gas processing	30.0 %	38.8 %	36.4 %	40.0 %
Total	100.0 %	100.0 %	100.0 %	100.0 %

We have hedges in place at September 30, 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)
October 2012 – December 2012	Ethane	29 (MBbls)	Index	$ 0.4329 /gal	$ 121
October 2012 – December 2012	Propane	16 (MBbls)	Index	$ 1.2828 /gal	235
October 2012 – December 2012	Normal Butane	9 (MBbls)	Index	$ 1.7208 /gal	87
October 2012 – December 2012	Natural Gasoline	6 (MBbls)	Index	$ 2.3211 /gal	86
					$ 529

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)
January 2013 – December 2013	Ethane	114 (MBbls)	Index	$ 0.4226 /gal	$ 285
January 2013 – December 2013	Propane	64 (MBbls)	Index	$ 1.1713 /gal	615
January 2013 – December 2013	Normal Butane	34 (MBbls)	Index	$ 1.7079 /gal	336
January 2013 – December 2013	Natural Gasoline	23 (MBbls)	Index	$ 2.2347 /gal	263
					$ 1,499

*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 58.9% of our hedgeable volumes at risk through December 2012 (32.8% of total volumes at risk through December 2012). We have also hedged 64.9% of our hedgeable volumes at risk for 2013 (34.3% of total volumes at risk for 2013).

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We also have hedges in place at September 30, 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)
October 2012–December 2012	Ethane	8 (MBbls)	Index	$ 0.3800 /gal*	$ 18
October 2012–December 2012	Propane	23 (MBbls)	Index	$ 1.3449 /gal*	400
October 2012–December 2012	Normal Butane	14 (MBbls)	Index	$ 1.7456 /gal*	160
October 2012–December 2012	Natural Gasoline	11 (MBbls)	Index	$ 2.2283 /gal*	111
October 2012–December 2012	Natural Gas	2,788 (MMBtu/d)	$ 4.7371 /MMBtu*	Index	(351)
					$ 338

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (In thousands)
January 2013–December 2013	Propane	59 (MBbls)	Index	$ 1.2621 /gal*	$ 793
January 2013–December 2013	Normal Butane	60 (MBbls)	Index	$ 1.6921 /gal*	545
January 2013–December 2013	Natural Gasoline	34 (MBbls)	Index	$ 2.2612 /gal*	426
January 2013–December 2013	Natural Gas	2,055 (MMBtu/d)	$ 3.5570 /MMBtu*	Index	213
					$ 1,977

* weighted average

In relation to our fractionation spread risk, as set forth above, we have hedged 39.4% of our hedgeable liquids volumes at risk through December 31, 2012 (9.8% of total liquids volumes at risk) and 45.5% of the related hedgeable PTR volumes through December 31, 2012 (9.9% of total PTR volumes). We have also hedged 28.5% of our hedgeable liquids volumes at risk for 2013 (6.4% of total liquids volumes at risk) and 35.4% of the related hedgeable PTR volumes for 2013 (7.0% 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 2.7% 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 September 30, 2012, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $4.2 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $2.0 million in the net fair value asset of these contracts as of September 30, 2012 to a net fair value asset of approximately $2.2 million.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At September 30, 2012, we had $5.5 million in borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $0.1 million for the year.

At September 30, 2012, we had fixed rate debt obligations of $714.8 and $250.0 million, consisting of our senior unsecured notes with an interest rate of 8.875% and 7.125%, respectively. The fair value of these fixed rate obligations was approximately $1,029.5

million as of September 30, 2012. We estimate that a 1% increase or decrease in interest rates would decrease or increase the fair value of such debt by $31.8 million and $14.3 million, respectively.

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 our Chief Executive Officer and Chief Financial Officer 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 (September 30, 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 September 30, 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 9, “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 nine months ended September 30, 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 set forth under the heading “Risk Factors” in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, which is incorporated by reference herein.

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	—	Certificate of Amendment to the Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period end June 30, 2012).
3.3	—	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).
3.4	—	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).
3.5	—	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).
3.6	—	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).
3.7	—	Amendment No. 4 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of September 13, 2012 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated September 13, 2012, filed with the Commission on September 14, 2012).
3.8	—	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).
3.9	—	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).
3.10	—	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).
3.11	—	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).
3.12	—	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).

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Number		Description
4.1		Registration Rights Agreement, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated May 23, 2012, filed with the Commission on May 24, 2012).
4.2		Supplemental Indenture, dated as of October 5, 2012, to the indenture governing the Issuers' $8^7/_8$% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors 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 October 2, 2012, filed with the Commission on October 5, 2012).
4.3		Supplemental Indenture, dated as of October 5, 2012, to the indenture governing the Issuers' $7^1/_8$% senior unsecured notes due 2022, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated October 2, 2012, filed with the Commission on October 5, 2012).
10.1		Sixth Amendment to Amended and Restated Credit Agreement, dated as of August 30, 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 August 30, 2012, filed with the Commission on August 31, 2012).
10.2		Common Unit Purchase Agreement, dated as of September 14, 2012, by and among Crosstex Energy, L.P., and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 14, 2012, filed with the Commission on September 14, 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 September 30, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2012 and 2011, (ii) Condensed Consolidated Balance Sheets as of September 30, 2012 and December 31, 2011, (iii) Consolidated Statements of Cash Flows for the nine months ended September 30, 2012 and 2011, (iv) Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2012 and 2011, (v) Consolidated Statements of Changes in Partners' Equity for the nine months ended September 30, 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

November 9, 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: November 9, 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: November 9, 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 September 30, 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

November 9, 2012

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

November 9, 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.