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, 2011

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 21, 2011, the Registrant had 50,656,490 common units outstanding.

TABLE OF CONTENTS

Table of Contents

CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

		September 30, 2011 (Unaudited)		December 31, 2010
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$	5,562	$	17,697
Accounts receivable:				
Trade, net of allowance for bad debt of $1,343 and $163, respectively		24,286		16,350
Accrued revenue and other		155,618		193,669
Fair value of derivative assets		4,160		5,523
Natural gas and natural gas liquids, prepaid expenses and other		11,911		9,741
Total current assets		201,537		242,980
Property and equipment, net of accumulated depreciation of $387,150 and $329,315, respectively		1,217,815		1,215,104
Fair value of derivative assets		288		1,169
Intangible assets, net of accumulated amortization of $186,402 and $151,735, respectively		464,308		498,975
Investment in limited liability company		35,000		—
Other assets, net		25,378		26,712
Total assets	$	1,944,326	$	1,984,940
LIABILITIES AND PARTNERS' EQUITY				
Current liabilities:				
Accounts payable, drafts payable and other	$	17,089	$	18,028
Accrued gas purchases		126,171		160,909
Fair value of derivative liabilities		6,453		7,980
Current portion of long-term debt		—		7,058
Other current liabilities		52,962		66,645
Total current liabilities		202,675		260,620
Long-term debt		787,934		711,512
Other long-term liabilities		24,672		26,879
Deferred tax liability		7,462		7,837
Fair value of derivative liabilities		166		1,156
Commitments and contingencies		—		—
Partners' equity		921,417		976,936
Total liabilities and partners' equity	$	1,944,326	$	1,984,940

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Condensed Consolidated Statements of Operations

		Three Months Ended September 30, 2011		2010		Nine Months Ended September 30, 2011		2010
		(Unaudited) (In thousands, except per unit amounts)						
Revenues	$	517,498	$	454,735	$	1,533,003	$	1,365,441
Operating costs and expenses:								
Purchased gas and NGLs		426,539		371,072		1,255,650		1,116,573
Operating expenses		28,126		26,476		81,083		78,365
General and administrative		13,712		11,277		38,111		35,669
(Gain) loss on sale of property		397		(588)		317		(14,367)
Loss on derivatives		563		1,582		5,520		6,872
Impairments		—		—		—		1,311
Depreciation and amortization		31,912		28,185		93,200		82,097
Total operating costs and expenses		501,249		438,004		1,473,881		1,306,520
Operating income		16,249		16,731		59,122		58,921
Other income (expense):								
Interest expense, net of interest income		(19,507)		(20,334)		(59,952)		(67,188)
Loss on extinguishment of debt		—		—		—		(14,713)
Other income		786		109		656		314
Total other expense		(18,721)		(20,225)		(59,296)		(81,587)
Loss before non-controlling interest and income taxes		(2,472)		(3,494)		(174)		(22,666)
Income tax provision		(287)		(161)		(898)		(809)

Net loss	(2,759)	(3,655)	(1,072)	(23,475)
Less: Net income (loss) attributable to the non-controlling interest	(23)	13	(130)	(11)
Net loss attributable to Crosstex Energy, L.P.	$ (2,736)	$ (3,668)	$ (942)	$ (23,464)
Preferred interest in net income attributable to Crosstex Energy, L.P.	$ 4,558	$ 3,676	$ 13,382	$ 9,926
Beneficial conversion feature attributable to preferred units	$ —	$ —	$ —	$ 22,279
General partner interest in net income (loss)	$ (76)	$ (820)	$ (709)	$ (3,596)
Limited partners' interest in net income (loss) attributable to Crosstex Energy, L.P.	$ (7,218)	$ (6,524)	$ (13,615)	$ (52,073)
Net income (loss) attributable to Crosstex Energy, L.P. per limited partners' unit:				
Basic and diluted common unit	$ (0.14)	$ (0.13)	$ (0.26)	$ (1.02)

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income (Loss)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Unaudited) (In thousands)			
Net loss	$ (2,759)	$ (3,655)	$ (1,072)	$ (23,475)
Hedging (gains) losses reclassified to earnings	421	(81)	1,510	1,637
Adjustment in fair value of derivatives	335	(601)	(1,200)	420
Comprehensive loss	(2,003)	(4,337)	(762)	(21,418)
Comprehensive (income) loss attributable to non-controlling interest	23	(13)	130	11
Comprehensive loss attributable to Crosstex Energy, L.P.	$ (1,980)	$ (4,350)	$ (632)	$ (21,407)

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Nine Months Ended September 30, 2011

	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, 2010	$ 807,020	50,255	$ 146,888	14,706	$ 20,979	1,325	$ (859)	$ 2,908	$ 976,936
Proceeds from exercise of unit options	513	111	—	—	—	—	—	—	513
Conversion of restricted units for common units, net of units withheld for taxes	(1,798)	294	—	—	—	—	—	—	(1,798)
Capital contributions	—	—	—	—	159	9	—	—	159
Stock-based compensation	3,107	—	—	—	2,397	—	—	—	5,504
Distributions	(44,222)	—	(12,647)	—	(2,266)	—	—	—	(59,135)
Net income (loss)	(13,615)	—	13,382	—	(709)	—	—	(130)	(1,072)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	1,510	—	1,510
Adjustment in fair value of derivatives	—	—	—	—	—	—	(1,200)	—	(1,200)
Balance, September 30, 2011	$ 751,005	50,660	$ 147,623	14,706	$ 20,560	1,334	$ (549)	$ 2,778	$ 921,417

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Nine Months Ended September 30,	
	2011	2010
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net loss	$ (1,072)	$ (23,475)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	93,200	82,097
(Gain) loss on sale of property	317	(14,367)
Impairments	—	1,311
Deferred tax benefit	(375)	(375)

Non-cash stock-based compensation	5,504	7,106
Derivatives mark to market interest rate settlement	—	(24,160)
Non-cash portion of derivatives loss	165	892
Non-cash portion of loss on debt extinguishment	—	5,396
Payment of interest paid-in-kind debt	—	(11,558)
Amortization of debt issue costs	5,278	5,213
Amortization of discount on notes	1,423	1,212
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	30,115	37,508
Natural gas and natural gas liquids, prepaid expenses and other	(3,493)	476
Accounts payable, accrued gas purchases and other accrued liabilities	(47,181)	(20,967)
Net cash provided by operating activities	83,881	46,309
Cash flows from investing activities:		
Additions to property and equipment	(62,829)	(29,762)
Insurance recoveries on property and equipment	—	2,599
Proceeds from sale of property	425	60,053
Investment in limited liability company	(35,000)	—
Net cash provided by (used in) investing activities	(97,404)	32,890
Cash flows from financing activities:		
Proceeds from borrowings	390,250	990,912
Payments on borrowings	(322,308)	(1,138,205)
Payments on capital lease obligations	(2,254)	(1,671)
Decrease in drafts payable	(103)	(5,214)
Debt refinancing costs	(3,936)	(28,520)
Conversion of restricted units, net of units withheld for taxes	(1,798)	(2,737)
Distributions to non-controlling interest	—	(261)
Distribution to partners	(59,135)	(6,250)
Proceeds from issuance of preferred units	—	120,786
Proceeds from exercise of unit options	513	667
Contributions from general partner	159	2,792
Net cash provided by (used in) financing activities	1,388	(67,701)
Net increase (decrease) in cash and cash equivalents	(12,135)	11,498
Cash and cash equivalents, beginning of period	17,697	779
Cash and cash equivalents, end of period	$ 5,562	$ 12,277
Cash paid for interest	$ 70,074	$ 63,769
Cash paid for income taxes	$ 905	$ 1,533

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

September 30, 2011
(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 and natural gas liquids (NGLs). 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. 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.

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

(a) Basis of Presentation

The accompanying condensed consolidated financial statements are prepared in accordance with the instructions to Form 10-Q, are unaudited and do not include all the information and disclosures required by generally accepted accounting principles for complete financial statements. All adjustments that, in the opinion of management, are necessary for a fair presentation of the results of operations for the interim periods have been made and are of a recurring nature unless otherwise disclosed herein. The results of operations for such interim periods are not necessarily indicative of results of operations for a full year. All significant intercompany balances and transactions have been eliminated in consolidation. Certain reclassifications have been made to the consolidated financial statements for the prior year to conform to the current presentation. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership's annual report on Form 10-K for the year ended December 31, 2010.

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

(b) Investment in Limited Liability Company

On June 22, 2011, the Partnership entered into a limited liability agreement with Howard Energy Partners ("HEP") for an initial capital contribution of $35.0 million in exchange for an individual ownership interest in HEP of approximately 35.0%. In addition the Partnership's contribution, an unrelated party also provided a capital contribution of $35.0 million for a 35.0% ownership interest in HEP with HEP management and a few private investors owning the remaining 30.0% interest. HEP operates and manages midstream services as well as pipeline and plant construction primarily in the Eagle Ford Shale in south Texas. This investment in HEP is accounted for under the equity method of accounting and is reflected on the balance sheet as "Investment in limited liability company." Per the terms of the agreement, the Partnership will not recognize any income from this investment until HEP's income exceeds approximately $9.9 million on an inception to date basis due to preferred interests owned by HEP management. If HEP has losses on an inception to date basis, the Partnership will recognize 39.3% of the losses.

(2) Long-Term Debt

As of September 30, 2011 and December 31, 2010, long-term debt consisted of the following (in thousands):

	September 30, 2011	December 31, 2010
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at September 30, 2011 and December 31, 2010 was 2.73% and 4.0%, respectively	$ 75,000	$ —
Senior unsecured notes (due 2018), net of discount of $12.1 million and $13.5 million, respectively, which bear interest at the rate of 8.875%	712,934	711,512
Series B secured note assumed in the Eunice transaction, which bore interest at the rate of 9.5%	—	7,058
	787,934	718,570
Less current portion	—	(7,058)
Debt classified as long-term	$ 787,934	$ 711,512

Credit Facility. As of September 30, 2011, there was $69.9 million in outstanding letters of credit and $75.0 million borrowed under the Partnership's bank credit facility, leaving approximately $340.1 million available for future borrowing based on the borrowing capacity of $485.0 million.

In May 2011, the Partnership amended its bank credit facility. The borrowing capacity under the credit facility was increased from $420.0 million to $485.0 million and the maturity was extended from February 2014 to May 2016. Additionally, the amendment to the Partnership's credit facility, among other things, (i) increased the maximum permitted leverage ratios during certain fiscal quarters, (ii) decreased the minimum consolidated interest rate coverage ratio during certain fiscal quarters and (iii) decreased the interest rate the Partnership pays on the obligations under the credit facility. Also under the amended credit facility, the Partnership increased the accordion from $100.0 million to $150.0 million, which permits the Partnership to increase its borrowing capacity if any bank in the credit facility or a new bank is willing to undertake such commitment.

In July 2011, the Partnership amended its bank credit facility again. The amendment to the Partnership's credit facility, among other things, (i) permitted Apache Midstream LLC ("Apache") to have a first priority lien on certain assets that are the subject of a joint interest arrangement between Apache and Crosstex Permian, LLC ("Permian") (including a new-build natural gas processing facility and related assets in the Permian Basin in West Texas) to secure obligations that Permian would owe to Apache should Permian fail to fund its obligations pursuant to the joint interest arrangement and (ii) increased the Partnership's ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under the credit agreement.

The credit facility is guaranteed by substantially all of the Partnership's subsidiaries and is secured by first priority liens on substantially all of the Partnership's assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of the Partnership's equity interests in substantially all of its subsidiaries and its interest in HEP.

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

Under the amended credit facility, borrowings bear interest at the Partnership's option at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. The Partnership pays a per annum fee (as described below) on all letters of credit issued under the amended credit facility and a commitment fee of between 0.375% and 0.50% per annum on the unused availability under the amended credit facility. The commitment fee, letter of credit fee and the applicable margins for the interest rate vary quarterly based on the Partnership's leverage ratio (as defined in the 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) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letter of Credit Fees
Greater than or equal to 4.50 to 1.00	2.00 %	3.00 %	3.00 %
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	1.75 %	2.75 %	2.75 %
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	1.50 %	2.50 %	2.50 %
Greater than or equal to 3.00 to 1.00 and less than 3.50 to 1.00	1.25 %	2.25 %	2.25 %
Less than 3.00 to 1.00	1.00 %	2.00 %	2.00 %

The amended credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The maximum permitted leverage ratio is 4.75 to 1.00. The maximum permitted senior leverage ratio (as defined in the credit facility, but generally computed as the ratio of total secured funded debt to

consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges), is 2.75 to 1.00. The minimum consolidated interest coverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is as follows:

· 2.25 to 1.00 for the fiscal quarters ending September 30, 2011, December 31, 2011, March 31, 2012 and June 30, 2012;

· 2.50 to 1.00 for September 30, 2012 and each fiscal quarter thereafter.

All other material terms of the credit facility are described in the Partnership's Annual Report on Form 10-K filing for the year ended December 31, 2010. The Partnership expects to be in compliance with all credit facility covenants for at least the next twelve months.

Series B Secured Note. On October 20, 2009, the Partnership acquired the Eunice natural gas liquids processing plant and fractionation facility which included an $18.1 million series B secured note. We paid $11.0 million of principal on the series B secured note in May 2010 and paid the remaining $7.1 million in May 2011.

Non Guarantors. The senior unsecured notes are jointly and severally guaranteed by each of the Partnership's current material subsidiaries (the "Guarantors"), with the exception of its regulated Louisiana subsidiaries (which may only guarantee up to $500.0 million of the Partnership's debt), CDC (the Partnership's joint venture in Denton County, Texas which is not 100% owned by the Partnership) and Crosstex Energy Finance Corporation (a wholly owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Partnership's indebtedness, including the senior unsecured notes). Guarantors may not sell or otherwise dispose of all or substantially all of their properties or assets, or consolidate with or merge into another company if such a sale would cause a default under the terms of the senior unsecured notes. Since certain wholly owned subsidiaries do not guarantee the senior unsecured notes, the condensed consolidating financial statements of the guarantors and non-guarantors for the three and nine months ended September 30, 2011 and 2010 are disclosed below in accordance with Rule 3-10 of Regulation S-X.

Condensed Consolidating Balance Sheets
September 30, 2011

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 187,416	$ 14,121	$ —	$ 201,537
Property, plant and equipment, net	999,245	218,570	—	1,217,815
Total other assets	524,971	3	—	524,974
Total assets	$ 1,711,632	$ 232,694	$ —	$ 1,944,326
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 195,541	$ 7,134	$ —	$ 202,675
Long-term debt	787,934	—	—	787,934
Other long-term liabilities	32,300	—	—	32,300
Partners' capital	695,857	225,560	—	921,417
Total liabilities & partners' capital	$ 1,711,632	$ 232,694	$ —	$ 1,944,326

December 31, 2010

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 229,997	$ 12,983	$ —	$ 242,980
Property, plant and equipment, net	987,018	228,086	—	1,215,104
Total other assets	526,853	3	—	526,856
Total assets	$ 1,743,868	$ 241,072	$ —	$ 1,984,940
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 254,460	$ 6,160	$ —	$ 260,620
Long-term debt	711,512	—	—	711,512
Other long-term liabilities	35,872	—	—	35,872
Partners' capital	742,024	234,912	—	976,936
Total liabilities & partners' capital	$ 1,743,868	$ 241,072	$ —	$ 1,984,940

Table of Contents

Condensed Consolidating Statements of Operations
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 income	786	—	—	786
Income (loss) before non-controlling interest and income taxes	(14,004)	11,532	—	(2,472)
Income tax provision	(283)	(4)	—	(287)
Net loss attributable to non-controlling interest	—	23	—	23
Net income (loss) attributable to Crosstex Energy, L.P.	$ (14,287)	$ 11,551	$ —	$ (2,736)

For the Three Months Ended September 30, 2010

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		

	Guarantors	Non Guarantors	Elimination	Consolidated
Total revenues	$ 439,264	$ 20,765	$ (5,294)	$ 454,735
Total operating costs and expenses	(434,949)	(8,349)	5,294	(438,004)
Operating income	4,315	12,416	—	16,731
Interest expense, net	(20,334)	—	—	(20,334)
Other income	109	—	—	109
Income (loss) before non-controlling interest and income taxes	(15,910)	12,416	—	(3,494)
Income tax provision	(159)	(2)	—	(161)
Net income attributable to non-controlling interest	—	(13)	—	(13)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (16,069)	$ 12,401	$ —	$ (3,668)

Table of Contents

For the Nine Months Ended September 30, 2011

	Guarantors	Non Guarantors (In thousands)	Elimination	Consolidated
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 income	656	—	—	656
Income (loss) 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 income (loss) attributable to Crosstex Energy, L.P.	$ (36,992)	$ 36,050	$ —	$ (942)

For the Nine Months Ended September 30, 2010

	Guarantors	Non Guarantors (in thousands)	Elimination	Consolidated
Total revenues	$ 1,321,810	$ 62,930	$ (19,299)	$ 1,365,441
Total operating costs and expenses	(1,299,802)	(26,017)	19,299	(1,306,520)
Operating income	22,008	36,913	—	58,921
Interest expense, net	(67,182)	(6)	—	(67,188)
Other expense	(14,399)	—	—	(14,399)
Income (loss) before non-controlling interest and income taxes	(59,573)	36,907	—	(22,666)
Income tax provision	(801)	(8)	—	(809)
Net loss attributable to non-controlling interest	—	11	—	11
Net income (loss) attributable to Crosstex Energy, L.P.	$ (60,374)	$ 36,910	$ —	$ (23,464)

Condensed Consolidating Statements of Cash Flow
For the Nine Months Ended September 30, 2011

	Guarantors	Non Guarantors (In thousands)	Elimination	Consolidated
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

For the Nine Months Ended September 30, 2010

	Guarantors	Non Guarantors (In thousands)	Elimination	Consolidated
Net cash flows provided by operating activities	$ 2,965	$ 43,344	$ —	$ 46,309
Net cash flows provided by (used in) investing activities	$ 39,924	$ (7,034)	$ —	$ 32,890
Net cash flows provided by (used in) financing activities	$ (67,441)	$ (36,571)	$ 36,311	$ (67,701)

Table of Contents

(3) Other Long-term Liabilities

Prior to January 1, 2011, the Partnership entered into 9 and 10-year capital leases for certain equipment. Assets under capital leases as of September 30, 2011 are summarized as follows (in thousands):

Compressor equipment	$ 37,199

Less: Accumulated amortization		(9,499)
Net assets under capital leases	$	27,700

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, 2011 (in thousands):

2011	$	1,146
2012 through 2015 ($4,582 annually)		18,328
Thereafter		16,680
Less: Interest		(7,034)
Net minimum lease payments under capital lease		29,120
Less: Current portion of net minimum lease payments		(4,448)
Long-term portion of net minimum lease payments	$	24,672

(4) Partners' Capital

(a) Cash Distributions

Unless restricted by the terms of the Partnership's credit facility and/or senior unsecured note indenture, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter.

The Partnership's first and second quarter 2011 distributions on its common and preferred units of $0.29 and $0.31 per unit were paid on May 13, 2011 and August 12, 2011, respectively. The Partnership's third quarter 2011 distribution on its common and preferred units of $0.31 per unit is to be paid on November 11, 2011.

(b) Earnings per Unit and Dilution Computations

The Partnership had common units and preferred units outstanding during the three and nine months ended September 30, 2011 and September 30, 2010. The preferred units were issued in January 2010 at a discount, which represents a beneficial conversion feature (BCF), totaling $22.3 million to the market price of the common units into which they are convertible. The BCFs attributable to the preferred units represent non-cash distributions that are treated in the same way as a cash distribution for earnings per unit computations for the nine months ended September 30, 2010.

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

Table of Contents

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, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Limited partners' interest in net loss	$ (7,218)	$ (6,524)	$ (13,615)	$ (52,073)
Distributed earnings allocated to:				
Common units (1) (2)	$ 15,705	$ 12,548	$ 46,020	$ 12,548
Unvested restricted units (1) (2)	298	271	883	271
Total distributed earnings	$ 16,003	$ 12,819	$ 46,903	$ 12,819
Undistributed loss allocated to:				
Common units	$ (22,808)	$ (18,972)	$ (59,411)	$ (63,298)
Unvested restricted units	(413)	(371)	(1,107)	(1,594)
Total undistributed loss	$ (23,221)	$ (19,343)	$ (60,518)	$ (64,892)
Net loss allocated to:				
Common units	$ (7,103)	$ (6,425)	$ (13,393)	$ (50,751)
Unvested restricted units	(115)	(99)	(222)	(1,322)
Total limited partners' interest in net loss	$ (7,218)	$ (6,524)	$ (13,615)	$ (52,073)
Basic and diluted net loss per unit:				
Basic and diluted common unit	$ (0.14)	$ (0.13)	$ (0.26)	$ (1.02)

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

(2) Three and nine months ended September 30, 2010 represents a declared distribution of $0.25 per unit paid on November 12, 2010.

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, 2011 and 2010 (in thousands):

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Basic and diluted weighted average units outstanding:				
Weighted average limited partner common units outstanding	50,650	50,142	50,562	49,872

All common unit equivalents were antidilutive in the three and nine months ended September 30, 2011 and September 30, 2010 because the limited partners were allocated net losses in these periods.

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

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

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Income allocation for incentive distributions	$ 600	$ —	$ 1,597	$ —
Stock-based compensation attributable to CEI's restricted shares	(634)	(762)	(2,334)	(3,063)
2% general partner interest in net loss	(42)	(58)	28	(533)
General partner share of net loss	$ (76)	$ (820)	$ (709)	$ (3,596)

Table of Contents

(5) 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, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Cost of share-based compensation charged to general and administrative expense	$ 1,304	$ 1,629	$ 4,569	$ 6,011
Cost of share-based compensation charged to operating expense	205	231	935	1,095
Total amount charged to income	$ 1,509	$ 1,860	$ 5,504	$ 7,106

(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, 2011 is provided below:

Crosstex Energy, L.P. Restricted Units:	Nine Months Ended September 30, 2011 Number of Units	Nine Months Ended September 30, 2011 Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,047,374	$ 10.30
Granted	384,910	15.39
Vested*	(410,418)	14.48
Forfeited	(61,851)	12.24
Non-vested, end of period	960,015	$ 10.42
Aggregate intrinsic value, end of period (in thousands)	$ 15,571	

* Vested units include 116,458 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued restricted units in 2011 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, 2011.

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, 2011 and 2010 are provided below (in thousands):

Crosstex Energy, L.P. Restricted Units:	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Aggregate intrinsic value of units vested	$ 329	$ 3,735	$ 6,438	$ 10,835
Fair value of units vested	$ 389	$ 2,643	$ 5,945	$ 5,497

As of September 30, 2011, there was $6.5 million of unrecognized compensation cost related to non-vested restricted units.

Table of Contents

That cost is expected to be recognized over a weighted-average period of 2.0 years.

(c) Unit Options

A summary of the unit option activity for the nine months ended September 30, 2011 is provided below:

Crosstex Energy, L.P. Unit Options:	Nine Months Ended September 30, 2011 Number of Units	Nine Months Ended September 30, 2011 Weighted Average Exercise Price
Outstanding, beginning of period	611,311	$ 6.77
Exercised	(111,729)	4.61
Forfeited	(27,031)	13.92
Expired	—	—
Outstanding, end of period	472,551	$ 6.90
Options exercisable at end of period	333,557	
Weighted average contractual term (years) end of period:		
Options outstanding	7.5	
Options exercisable	7.2	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 4,887	
Options exercisable	$ 3,466	

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, 2011 and September 30, 2010 are provided below (in thousands):

Crosstex Energy, L.P. Unit Options:	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Intrinsic value of unit options exercised	$ 348	$ 727	$ 1,333	$ 1,016
Fair value of unit options vested	$ 1	$ 469	$ 562	$ 762

As of September 30, 2011, there was $0.3 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted average period of 1.3 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, 2011 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Nine Months Ended September 30, 2011 Number of Shares	Nine Months Ended September 30, 2011 Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,108,998	$ 8.64
Granted	616,284	9.44
Vested*	(412,185)	13.64
Forfeited	(79,994)	8.28
Non-vested, end of period	1,233,103	$ 7.39
Aggregate intrinsic value, end of period (in thousands)	$ 16,622	

* Vested shares include 113,021 shares withheld for payroll taxes paid on behalf of employees.

Table of Contents

CEI issued restricted shares in 2011 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, 2011.

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, 2011 and September 30, 2010 are provided below (in thousands):

	Three Months Ended	Nine Months Ended

Crosstex Energy, Inc. Restricted Shares:	September 30, 2011		September 30, 2010		September 30, 2011		September 30, 2010	
Aggregate intrinsic value of shares vested	$	226	$	2,330	$	3,915	$	3,143
Fair value of shares vested	$	342	$	2,972	$	5,623	$	4,309

As of September 30, 2011 there was $6.0 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 2.1 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, 2011.

(6) Derivatives

Commodity Swaps

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

The Partnership commonly enters into various derivative financial transactions which it does not designate as accounting hedges. These transactions include "swing swaps," "third party on-system financial swaps," "storage swaps," "basis swaps," "processing margin swaps," "liquids swaps" and "put options." Swing swaps are generally short-term in nature (one month) and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers, and simultaneously enters into the derivative transaction. Storage swap transactions protect against changes in the value of products that the Partnership has stored to serve various operational requirements (gas) or has in inventory due to short term constraints in moving the product to market (liquids). Basis swaps are used to hedge basis location price risk due to buying gas into one of the Partnership's systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge fractionation spread risk at the Partnership's processing plants relating to the option to process versus bypassing the Partnership's equity gas. Liquids financial swaps are used to hedge price risk on percent of liquids (POL) contracts. Put options are purchased to hedge against declines in pricing and as such represent options, not obligations, to sell the related underlying volumes at a fixed price.

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

	Three Months Ended September 30, 2011		Three Months Ended September 30, 2010		Nine Months Ended September 30, 2011		Nine Months Ended September 30, 2010	
Change in fair value of derivatives that do not qualify for hedge accounting	$	(619)	$	1,473	$	111	$	958
Realized losses on derivatives		1,227		109		5,355		5,975
Ineffective portion of derivatives qualifying for hedge accounting		(45)		—		(127)		(61)
Net losses related to commodity swaps	$	563	$	1,582	$	5,339	$	6,872
Put option premium mark to market		—		—		181		—
Losses on derivatives	$	563	$	1,582	$	5,520	$	6,872

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

	September 30, 2011		December 31, 2010	
Fair value of derivative assets — current, designated	$	230	$	1
Fair value of derivative assets — current, non-designated		3,930		5,522
Fair value of derivative assets — long term, designated		101		—
Fair value of derivative assets — long term, non-designated		187		1,169
Fair value of derivative liabilities — current, designated		(945)		(1,066)
Fair value of derivative liabilities — current, non-designated		(5,508)		(6,914)
Fair value of derivative liabilities — long term, designated		(15)		—
Fair value of derivative liabilities — long term, non-designated		(151)		(1,156)
Net fair value of derivatives	$	(2,171)	$	(2,444)

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, 2011 (all gas volumes are expressed in MMBtu's and liquids volumes are expressed in gallons). The remaining term of the contracts extend no later than December 2012 for derivatives. Changes in the fair value of the Partnership's mark to market derivatives are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings. The ineffective portion is recorded in earnings immediately.

Transaction Type	September 30, 2011 Volume	Fair Value	
	(In thousands)		
*Cash Flow Hedges:**			
Liquids swaps (short contracts)	(8,668)	$	(629)
Total swaps designated as cash flow hedges		$	(629)
*Mark to Market Derivatives:**			

Swing swaps (short contracts)	(1,519)	$ (11)
Physical offsets to swing swap transactions (long contracts)	1,519	—
Basis swaps (long contracts)	9,615	2,669
Physical offsets to basis swap transactions (short contracts)	(155)	465
Basis swaps (short contracts)	(9,305)	(2,626)
Physical offsets to basis swap transactions (long contracts)	155	(558)
Processing margin hedges — liquids (short contracts)	(12,523)	(438)
Processing margin hedges — gas (long contracts)	1,576	(1,175)
Processing margin hedges — gas (short contracts)	(86)	59
Liquids swaps - non-designated (short contracts)	(730)	(12)
Storage swap transactions — gas (short contracts)	(70)	73
Liquid put options (purchased)	3,122	12
Total mark to market derivatives		$ (1,542)

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

Table of Contents

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits and monitors the appropriateness of these limits on an ongoing basis. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of September 30, 2011 of $4.9 million would be reduced to $1.9 million due to the netting feature, all of which relates to other energy companies.

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	**2011**	**2010**	**2011**	**2010**
Liquids realized loss included in Midstream revenue	$ (527)	$ (13)	$ (2,235)	$ (1,123)

Natural Gas

As of September 30, 2011, the Partnership has no balances in accumulated other comprehensive income related to natural gas.

Liquids

As of September 30, 2011, an unrealized derivative fair value net loss of $0.6 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive loss, all of which is expected to be reclassified into earnings through September 2012. 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, liquids swaps and put options purchased 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, 2011	$ (1,578)	$ 36	$ —	$ (1,542)

(7) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available,

Table of Contents

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, 2011 Level 2	December 31, 2010 Level 2
Commodity Swaps*	$ (2,171)	$ (2,444)
Total	$ (2,171)	$ (2,444)

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

Fair Value of Financial Instruments

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

	September 30, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 787,934	$ 818,125	$ 718,570	$ 768,308
Obligations under capital lease	$ 29,120	$ 25,971	$ 31,327	$ 28,807

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 $75.0 million in borrowings under its revolving credit facility included in long-term debt as of September 30, 2011 and no borrowings at December 31, 2010. 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, 2011 and December 31, 2010, the Partnership also had borrowings totaling $712.9 million and $711.5 million, net of discount, respectively, under senior unsecured notes with a fixed rate of 8.875% and a series B secured note with a principal amount of $7.1 million as of December 31, 2010 with a fixed rate of 9.5%. The fair value of the senior unsecured notes as of September 30, 2011 and December 31, 2010 was based on third party market quotations. The fair value of the series B secured note as of December 31, 2010 was adjusted to reflect current market interest rates for such borrowings on that date.

Table of Contents

(8) Commitments and Contingencies

(a) Employment and Severance Agreements

Certain members of management of the Partnership are parties to employment and/or severance agreements with the general partner. The employment and severance agreements provide those managers with severance payments in certain circumstances and, in the case of employment agreements, prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

(b) Environmental Issues

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

In addition, the Partnership disclosed possible Clean Air Act monitoring deficiencies it has discovered to the Louisiana Department of Environmental Quality (LDEQ) and is working with the agency to correct these deficiencies and to address modifications to facilities to ensure compliance. The Partnership does not expect to incur any material environmental liability associated with these issues.

In June 2011, the Partnership notified the Texas Commission of Environmental Quality that it would conduct an internal audit of its North Texas operations under the Texas Environmental, Health & Safety Audit Privilege Act (Audit Act). Under the Audit Act, the Partnership will be able to conduct an audit of its facilities and make disclosures pursuant to Section 10(g) of the Audit Act, which provides immunity from penalties for violations voluntarily disclosed as a result of the compliance audit. Pursuant to Section 4(e), the audits will be completed no later than six (6) months after the date of their commencement. The Partnership is targeting December 2011 for completion of the audit.

(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 lawsuit alleges that the plaintiffs have incurred at least $65.0 million in damages, including damage to equipment and lost profits. The Partnership has submitted the claim to its insurance carriers and intends to vigorously defend the lawsuit. The Partnership believes that any recovery would be within applicable policy limits. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

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

The Partnership (or its subsidiaries) is defending a number of lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the

industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

(9) Segment Information

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

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

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

	LIG	NTX	PNGL	Corporate	Totals
			(In thousands)		
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 and NGLs	$ (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
Three Months Ended September 30, 2010:					
Sales to external customers	$ 232,220	$ 85,510	$ 137,005	$ —	$ 454,735
Sales to affiliates	18,228	20,516	—	(38,744)	—
Purchased gas and NGLs	(221,624)	(66,207)	(121,985)	38,744	(371,072)
Operating expenses	(7,877)	(11,525)	(7,074)	—	(26,476)
Segment profit	$ 20,947	$ 28,294	$ 7,946	$ —	$ 57,187
Gain (loss) on derivatives	$ (1,561)	$ (70)	$ 49	$ —	$ (1,582)
Depreciation, amortization and impairments	$ (3,114)	$ (15,896)	$ (8,058)	$ (1,117)	$ (28,185)
Capital expenditures	$ 3,006	$ 14,635	$ 1,389	$ 810	$ 19,840
Identifiable assets	$ 327,418	$ 1,111,274	$ 473,668	$ 52,476	$ 1,964,836

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 and NGLs	(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
Nine Months Ended September 30, 2010:					
Sales to external customers	$ 677,750	$ 236,517	$ 451,174	$ —	$ 1,365,441
Sales to affiliates	62,201	66,106	6	(128,313)	—
Purchased gas and NGLs	(653,515)	(184,370)	(407,001)	128,313	(1,116,573)
Operating expenses	(24,140)	(34,793)	(19,432)	—	(78,365)
Segment profit	$ 62,296	$ 83,460	$ 24,747	$ —	$ 170,503
Gain (loss) on derivatives	$ (2,465)	$ (4,577)	$ 170	$ —	$ (6,872)
Depreciation, amortization and impairments	$ (9,186)	$ (47,000)	$ (23,886)	$ (3,336)	$ (83,408)
Capital expenditures	$ 8,908	$ 20,015	$ 2,309	$ 1,491	$ 32,723
Identifiable assets	$ 327,418	$ 1,111,274	$ 473,668	$ 52,476	$ 1,964,836

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,	
	2011	2010	2011	2010
Segment profits	$ 62,833	$ 57,187	$ 196,270	$ 170,503
General and administrative expenses	(13,712)	(11,277)	(38,111)	(35,669)
Loss on derivatives	(563)	(1,582)	(5,520)	(6,872)
Gain (loss) on sale of property	(397)	588	(317)	14,367
Depreciation, amortization and impairments	(31,912)	(28,185)	(93,200)	(83,408)
Operating income	$ 16,249	$ 16,731	$ 59,122	$ 58,921

(10) Immaterial Correction of Prior Period Financial Statements

During the three months ended September 30, 2011, the Partnership determined certain immaterial corrections were required for previously-issued financial statements as discussed below. The corrections did not impact the Partnership's operating income and were not considered material to the Partnership's revenues and costs for the applicable periods.

The Partnership determined that revenues and purchased gas costs related to a new gas purchase arrangement were improperly classified as energy trading activities resulting in the netting of revenue and purchased gas which should have been shown on a gross basis in its previously-issued financial statements for the three months ended March 31, 2011 and June 30, 2011. As a result both revenues and purchased gas were understated by $39.5 million and $29.6 million for the three months ended March 31, 2011 and June 30, 2011. The following table reflects the revenues, purchased gas costs and total operating costs and expenses as previously reported and as corrected for the three months ended March 31, 2011 and June 30, 2011 (in thousands):

	Three Months Ended March 31, 2011	Three Months Ended June 30, 2011
As previously reported:		
Total revenues	$ 450,315	$ 496,147
Purchased gas and NGLs	360,478	399,589
Total operating costs and expenses	430,332	473,257
Operating income	19,983	22,890
As corrected:		
Total revenues	$ 489,770	$ 525,735
Purchased gas and NGLs	399,933	429,177
Total operating costs and expenses	469,787	502,845
Operating income	19,983	22,890

Table of Contents

(11) Subsequent Event

Subsequent to the quarter ended September 30, 2011 and prior to the issuance of the unaudited condensed consolidated financial statements, the Partnership evaluated and found no events material to the financial statement presentation during this period.

Table of Contents

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

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

Overview

We are a Delaware limited partnership formed on July 12, 2002. Our primary focus is on the gathering, processing, transmission and marketing of natural gas and natural gas liquids (NGLs), which we manage as regional reporting segments of midstream activity. Our geographic focus is in the north Texas Barnett Shale (NTX) and in Louisiana which has two reportable business segments (the pipelines and processing plants located in Louisiana, or LIG, and the south Louisiana processing and NGL assets, or PNGL). Our recently announced expansion project with Apache Corporation also gives us a presence in the Permian Basin in west Texas, and our recent investment in HEP gives us access to activity in the Eagle Ford Shale in south Texas as described in more detail in the Recent Developments section below. We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas for a margin, or to gather, process, transport or market natural gas and NGLs for a fee. We define gross operating margin as operating revenue minus cost of purchased gas and NGLs. Gross operating margin is a non-GAAP financial measure and is explained in greater detail under “Non-GAAP Financial Measures” below.

Our gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, and the volumes of NGLs handled at our fractionation facilities. We generate revenues from four 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; and
- providing compression services.

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

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

We have recorded a loss of approximately $9.5 million during the nine months ended September 30, 2011 on the Delivery Contract. We currently expect that we will record an additional loss of approximately $3.5 million on the Delivery Contract for the remainder of the year ending December 31, 2011. This estimate is based on forward prices, basis spreads and other market assumptions as of September 30, 2011. These assumptions are subject to change if market conditions change during the remainder of

2011, and actual results under the Delivery Contract in 2011 could be substantially different from our current estimates, which may result in a greater loss than currently estimated.

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

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

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

Recent Developments

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 of approximately 35.0%. In addition to our contribution, an unrelated party also provided a capital contribution of $35.0 million for a 35.0% ownership interest in HEP with HEP management and a few private investors owning the remaining 30.0% interest. HEP operates and manages midstream services as well as pipeline and plant construction primarily in the Eagle Ford Shale in south Texas.

Credit Facility. On May 2, 2011 and July 11, 2011, we amended our bank credit facility. The May 2011 amendment increased our borrowing capacity from $420.0 million to $485.0 million, extended the maturity from February 2014 to May 2016, reduced interest rates and improved terms of other covenants under the facility. The July 2011 amendment permitted Apache Midstream LLC (“Apache”) to have a first priority lien on certain assets that are associated with our joint interest arrangement with Apache and increased our ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under the credit agreement. See Note (2) to the condensed consolidated financial statements for a discussion of the amended terms.

Asset Expansions. We completed two expansion projects discussed more fully below on our natural gas gathering system in the Barnett Shale play in North Texas that became operational in March 2011. We also reactivated our Eunice NGL fractionators in south central Louisiana to give us operational flexibility, increase our fractionation capacity and give us the ability to capture new NGL-related business. The Eunice NGL fractionators became operational in early April 2011 and are equipped to accommodate 15,000 barrels of NGLs per day ("Bbls/d").

We expanded our natural gas gathering system in North Texas with the construction of a $25.0 million, 15-mile pipeline extension to serve major Barnett Shale producers. The project, which is supported by volumetric commitments, includes a seven-mile low-pressure pipeline, an eight-mile high-pressure pipeline and a compressor station in southwest Tarrant County that provides customers with greater takeaway capacity to accommodate their transportation requirements.

We also entered into a 10-year firm gathering and compression agreement with a major Barnett Shale producer for an additional 50 MMcf/d on our North Texas gathering system. We constructed a compressor station on an existing gathering line to accommodate the customer's transportation requirements.

Expansion into Permian Basin. On July 11, 2011, we entered into an agreement with Apache to jointly construct a new natural gas processing facility in the Permian Basin in west Texas with an estimated capital cost of $85.0 million. We will fund the processing project equally with Apache and we will each hold a 50 percent undivided working interest in the plant. We are managing the construction of the plant which began in July and is scheduled to be completed in June 2012. We will also manage the operation of the plant which is expected to commence its initial phase of operations in January 2012. Separately, we have purchased and are upgrading a nearby rail terminal to provide transportation of NGLs by rail to our Eunice fractionation facility in southern Louisiana.

Table of Contents

Pipeline Expansion. On July 25, 2011, we announced that we are completing engineering studies, pipeline routing work and environmental permitting for a NGL project that will expand our Louisiana fractionation facilities and expand access to these facilities and Louisiana product markets through a new NGL pipeline. The new pipeline will be an extension of our 440-mile Cajun-Sibon NGL pipeline that is connected to our Eunice NGL fractionation facilities in south central Louisiana. The new 130-mile NGL pipeline extension will connect the Eunice fractionation facilities to Mont Belvieu supply pipelines and will have an initial capacity of 70,000 barrels per day of raw-make NGLs. The project also includes the expansion of our Eunice NGL fractionation facilities from 15,000 barrels to 55,000 barrels of NGLs per day, which will increase our interconnected fractionation capacity in Louisiana to approximately 97,000 barrels per day of NGLs. Our investment for the project is currently estimated at $180.0 million to $220.0 million over the next two years. We expect to fund this capital project from the proceeds of borrowings under our bank credit facility and from debt and equity sources once we contract a sufficient level of NGL supply commitments to proceed with the construction of the pipeline.

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, loss on extinguishment of debt, (gain) loss on noncash derivatives, transaction costs associated with successful transactions and minority interest; less gain on sale of property. Adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

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

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

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Our 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.

Table of Contents

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)			
Net loss attributable to Crosstex Energy, L.P.	$ (2.7)	$ (3.7)	$ (0.9)	$ (23.5)
Interest expense	19.5	20.3	60.0	67.2
Depreciation and amortization	31.9	28.2	93.2	82.1
Impairment	—	—	—	1.3
Loss on extinguishment of debt	—	—	—	14.7
(Gain) loss on sale of property	0.4	(0.6)	0.3	(14.4)
Stock-based compensation	1.5	1.9	5.5	7.1

Other (a)		(0.5)		1.7		1.3		2.2
Adjusted EBITDA	$	50.1	$	47.8	$	159.4	$	136.7

(a) Includes financial derivatives marked-to-market; income taxes; transaction costs associated with successful transactions and minority interest.

We define gross operating margin, generally, as revenues minus cost of purchased gas and NGLs. We present gross operating margin by segment in "Results of Operations." We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because our business is generally to purchase and resell natural gas for a margin or to gather, process, transport or market natural gas and NGLs for a fee. Operating expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. These expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. We do not deduct operating expenses from total revenue in calculating gross operating margin because we separately evaluate commodity volume and price changes in these margin amounts. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful 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,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
	(In millions)							
Total gross operating margin	$	91.0	$	83.6	$	277.3	$	248.9
Add (deduct):								
Operating expenses		(28.1)		(26.4)		(81.1)		(78.4)
General and administrative expenses		(13.7)		(11.3)		(38.1)		(35.7)
Gain (loss) on sale of property		(0.4)		0.6		(0.3)		14.4
Loss on derivatives		(0.6)		(1.6)		(5.5)		(6.9)
Depreciation, amortization and impairments and other		(31.9)		(28.2)		(93.2)		(83.4)
Operating income	$	16.3	$	16.7	$	59.1	$	58.9

Table of Contents

Results of Operations

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
	(Dollars in millions)							
LIG Segment								
Revenues	$	222.2	$	250.4	$	692.7	$	740.0
Purchased gas and NGLs		(189.4)		(221.6)		(596.3)		(653.5)
Total gross operating margin	$	32.8	$	28.8	$	96.4	$	86.5
NTX Segment								
Revenues	$	110.4	$	106.0	$	322.1	$	302.6
Purchased gas and NGLs		(67.0)		(66.2)		(194.6)		(184.4)
Total gross operating margin	$	43.4	$	39.8	$	127.5	$	118.2
PNGL Segment								
Revenues	$	233.8	$	137.0	$	656.7	$	451.2
Purchased gas and NGLs		(219.0)		(122.0)		(603.3)		(407.0)
Total gross operating margin	$	14.8	$	15.0	$	53.4	$	44.2
Corporate								
Revenues	$	(48.9)	$	(38.7)	$	(138.5)	$	(128.3)
Purchased gas and NGLs		48.9		38.7		138.5		128.3
Total gross operating margin	$	—	$	—	$	—	$	—
Total								
Revenues	$	517.5	$	454.7	$	1,533.0	$	1,365.5
Purchased gas and NGLs		(426.5)		(371.1)		(1,255.7)		(1,116.6)
Total gross operating margin	$	91.0	$	83.6	$	277.3	$	248.9
Midstream Volumes:								
LIG								
Gathering and Transportation (MMBtu/d)		859,000		883,000		907,000		895,000
Processing (MMBtu/d)		236,000		284,000		244,000		285,000
NTX								
Gathering and Transportation (MMBtu/d)		1,121,000		1,080,000		1,120,000		1,079,000
Processing (MMBtu/d)		258,000		224,000		248,000		210,000
PNGL								
Processing (MMBtu/d)		699,000		878,000		837,000		886,000
NGL Fractionation (Gals/d)		987,000		972,000		1,088,000		934,000
Commercial Services (MMBtu/d)		252,000		123,000		212,000		73,000

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010

Gross Operating Margin. Gross operating margin was $91.0 million for thethree months ended September 30, 2011 compared to $83.6 million for the three months ended September 30, 2010, an increase of $7.4 million, or 8.9%. The increase was due to a favorable processing environment. The following provides additional details regarding this change in gross operating margin:

- The LIG segment contributed gross operating margin growth of $4.0 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010. The continued strength of the processing environment contributed to a gross operating margin increase of $7.2 million. The Plaquemine and Gibson plants were the primary drivers of the overall gain with a combined gross operating margin increase of $4.7 million. Other treating and processing activity on the system contributed a gross operating margin increase of $2.5 million. The processing gains were offset by a decrease in gross operating margin of $3.2 million on the gathering and transmission assets.

- The NTX segment had gross operating margin improvement of $3.6 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010. An increase in throughput volume on the gathering and transmission assets in north Texas was the primary contributor to a gross operating margin increase of $3.3 million. The north Texas processing plants also had a gross operating margin increase of $1.5 million for the comparable periods due to increased supply and a favorable processing environment. 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 gross operating margin decline of $0.2 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010. The Blue Water processing plant contributed a gross operating margin increase of $1.4 million for the comparable period which was offset by a NGL inventory loss.

Table of Contents

Operating Expenses. Operating expenses were $28.1 million for the three months ended September 30, 2011 compared to $26.5 million for the three months ended September 30, 2010, an increase of $1.7 million, or 6.2%. The increase is primarily a result of the following:

- Increase in labor and benefits expense of $1.2 million primarily related to an increase in employee headcount for activity related to project expansions;
- Increase in operations activity resulted in increased cost of $1.2 million primarily related to chemicals, supplies and electric utilities;
- Increase was partially offset with savings in ad valorem taxes and integrity testing cost from 2010.

General and Administrative Expenses. General and administrative expenses were $13.7 million for the three months ended September 30, 2011 compared to $11.3 million for the three months ended September 30, 2010, an increase of $2.4 million, or 21.2%. The increase is primarily due to the following:

- Labor and benefits expense increase of $0.8 million related to increase in headcount;
- Increase of $1.1 million primarily related to legal and other professional fees;
- Bad debt expense increase of $1.1 million related to uncollectible gathering fees related to a particular customer.

Gain/Loss on Derivatives. We had a loss on derivatives of $0.6 million for the three months ended September 30, 2011 compared to a loss of $1.6 million for the three months ended September 30, 2010. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Three Months Ended September 30,			
	2011		2010	
	Total	Realized	Total	Realized
Basis swaps	$ (0.2)	$ (0.2)	$ —	$ (0.5)
Processing margin hedges	0.6	1.3	1.7	0.5
Other	0.2	0.1	(0.1)	—
Net losses related to commodity swaps	$ 0.6	$ 1.2	$ 1.6	$ —

Depreciation and Amortization. Depreciation and amortization expenses were $31.9 million for the three months ended September 30, 2011 compared to $28.2 million for the three months ended September 30, 2010, an increase of $3.7 million, or 13.1%. The increase includes $3.7 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 $19.5 million for the three months ended September 30, 2011 compared to $20.3 million for the three months ended September 30, 2010, a decrease of $0.8 million, or 3.9%. Net interest expense consists of the following (in millions):

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010
Senior notes	$ 16.6	$ 16.9
Bank credit facility	1.4	1.4
Amortization of debt issue costs	1.2	1.5
Other	0.3	0.5
Total	$ 19.5	$ 20.3

Table of Contents

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Gross Operating Margin. Gross operating margin was $277.3 million for the nine months ended September 30, 2011 compared to $248.9 million for the nine months ended September 30, 2010, an increase of $28.4 million, or 11.4%. The increase was due to a favorable processing and NGL environment as well as increased throughput volumes on our gathering and transmission systems. The following provides additional details regarding this change in gross operating margin:

- The LIG segment contributed gross operating margin growth of $9.9 million for thenine months ended September 30, 2011 compared to the nine months ended September 30, 2010. The favorable processing environment led to a $14.7 million increase in the combined gross operating margin for the LIG processing plants from the comparable periods. The Gibson and Plaquemine plants were the primary contributor to this gain with gross operating margin increases of $4.8 million and $2.7 million, respectively. Other treating and processing activity contributed an additional gross operating margin increase of $7.2 million. This increase was partially offset due to gross operating margin decline of approximately $4.8 million on our gathering and transmission assets.

- The NTX segment had a gross operating margin increase of $9.3 million for thenine months ended September 30, 2011 compared to the nine months ended September 30, 2010. An increase in throughput volume was the primary contributor to a gross operating margin increase of $10.0 million on the gathering and transmission assets. The north Texas processing plants also had a gross operating margin increase of $3.4 million for the comparable periods due to increased supply and the favorable processing environment. These increases were partially offset by an increase in losses of $4.1 million on the Delivery Contract discussed more fully under "Overview".

- The favorable processing and NGL marketing environment contributed to a $9.2 million increase in gross operating margin for the PNGL segment for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. The Blue Water, Pelican and Eunice processing plants contributed gross operating margin increases of $4.3 million, $3.3 million and $0.9 million, respectively. NGL fractionation and marketing activity generated a gross operating margin increase of approximately $1.2 million which was offset by a NGL inventory loss.

Operating Expenses. Operating expenses were $81.1 million for the nine months ended September 30, 2011 compared to $78.4 million for the nine months ended September 30, 2010, an increase of $2.7 million, or 3.4%. The increase is primarily a result of the following:

- Increase in labor and benefits expense of $2.8 million primarily related to an increase in employee headcount for activity related to project expansions;
- Increase in bulk chemical, supplies and service fees of $1.2 million for increased operations activity;
- Increase in electric utility cost of $0.7 million related to increase in operations at the processing plants;
- Decrease of $1.0 million primarily related to periodic integrity testing incurred in 2010; and
- Decrease of $0.9 million related to ad valorem taxes.

General and Administrative Expenses. General and administrative expenses were $38.1 million for the nine months ended September 30, 2011 compared to $35.7 million for the nine months ended September 30, 2010, an increase of $2.4 million, or 6.7%. The increase is primarily a result of the following:

- Labor and benefits expense increase of $1.8 million primarily related to increase in headcount;
- Increase of $0.6 million primarily related to legal and consulting fees;
- Bad debt expense increase of $0.9 million related to uncollectible gathering fees; and
- Stock based compensation expense decrease of $1.4 million.

Gain/Loss on sale of Property. Loss on sale of property was $0.3 million for the nine months ended September 30, 2011 compared to a $14.4 million gain for the nine months ended September 30, 2010. The loss on sale of property for the nine months ended September 30, 2011 was related to the sale of a minor section of pipeline in Louisiana in September 2011. The gain on sale of property for the nine months ended September 30, 2010 was related to the sale of our east Texas assets in January 2010.

Gain/Loss on Derivatives. Loss on derivatives was $5.5 million for the nine months ended September 30, 2011 compared to a loss of $6.9 million for the nine months ended September 30, 2010. The derivative transaction types contributing to the net loss are as follows (in millions):

	Nine Months Ended September 30,			
	2011		2010	
	Total	Realized	Total	Realized
Basis swaps	$ 0.8	$ 0.9	$ 4.8	$ 1.8
Processing margin hedges	4.5	4.5	2.3	4.0
Other	0.2	—	(0.2)	0.1
Net losses related to commodity swaps	$ 5.5	$ 5.4	$ 6.9	$ 5.9

Table of Contents

Impairments. There was no impairment expense for the nine months ended September 30, 2011 and $1.3 million of impairment expense for the nine months ended September 30, 2010. The impairment expense in 2010 primarily relates to the write down of certain excess pipe inventory prior to its sale.

Depreciation and Amortization. Depreciation and amortization expenses were $93.2 million for the nine months ended September 30, 2011 compared to $82.1 million for the nine months ended September 30, 2010, an increase of $11.1 million, or 13.5%. The increase includes $8.5 million due to intangible amortization related to the downward revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in North Texas. In addition, depreciation expense increased $2.6 million primarily due to an increase of assets placed in service in our North Texas and LIG regions.

Interest Expense. Interest expense was $60.0 million for the nine months ended September 30, 2011 compared to $67.2 million for the nine months ended September 30, 2010. Net interest expense consists of the following (in millions):

	Nine Months Ended September 30,	
	2011	2010
Senior notes (secured and unsecured)	$ 49.7	$ 45.9
Paid-in-kind interest on senior secured notes	—	1.4
Bank credit facility	4.0	8.8
Mark to market interest rate swaps	—	(22.4)
Realized interest rate swap losses	—	26.5
Amortization and write off of debt issue costs	5.3	5.2
Other	1.0	1.8
Total	$ 60.0	$ 67.2

Loss on Extinguishment of Debt. Loss on extinguishment of debt for the nine months ended September 30, 2010 was $14.7 million. In February 2010, we repaid our prior credit facility and senior secured notes which resulted in make-whole interest payments on our senior secured notes and the write-off of unamortized debt costs totaling $14.7 million.

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, 2010.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $83.9 million for the nine months ended September 30, 2011 compared to net cash provided by operating activities of $46.3 million for nine months ended September 30, 2010. 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, 2011	Nine Months Ended September 30, 2010
Income before non-cash income and expenses	$ 104.4	$ 29.3
Changes in working capital	$ (20.6)	$ 17.0

The increase in cash flow from income before non-cash income and expenses of $75.1 million from 2010 to 2011 resulted from payments in 2010 for settlements of interest rate swaps, make-whole payments, and payment-in-kind notes associated with the extinguishment of debt combined with an increase in gross margin and a decrease in interest expense in the first nine months of 2011 as compared to the first nine months of 2010.

Table of Contents

Cash Flows from Investing Activities. Net cash used in investing activities was $97.4 million for the nine months ended September 30, 2011 and net cash provided by investing activities was $32.9 million for the nine months ended September 30, 2010. Cash flows from investing activities for the nine months ended September 30, 2010 includes, among other things, proceeds from property sales of $60.0 million related to the sale of east Texas assets and a non-operational processing plant held in inventory. Our primary investing outflows were capital expenditures, net of accrued amounts, and an investment in HEP as follows (in millions):

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Growth capital expenditures	$ 53.4	$ 23.8
Maintenance capital expenditures	9.4	6.0
Investment in Howard Energy Partners	35.0	—
Total	$ 97.8	$ 29.8

Cash Flows from Financing Activities. Net cash provided by financing activities was $1.4 million for the nine months ended September 30, 2011 and net cash used in financing activities was $67.7 million for the nine months ended September 30, 2010. Our primary financing activities consist of the following (in millions):

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Net borrowings (repayments) under bank credit facility	$ 75.0	$ (530.7)
Senior secured note repayments	—	(316.5)
Senior unsecured note borrowings (net of discount on the note)	—	711.0
Series B senior secured note repayment	(7.1)	(11.1)
Net repayments under capital lease obligations	(2.3)	(1.7)
Debt refinancing costs	(3.9)	(28.5)
Preferred units	—	120.8

Distributions to unitholders and our general partner also represent a primary use of cash in financing activities. No cash distributions were paid to common unitholders or the general partner during the nine months ended September 30, 2010 due to our continued focus on reducing leverage. Total cash distributions made during the nine months ended September 30, 2011 were as follows (in millions):

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Common units	$ 44.2	$ —
Preferred units	12.6	6.2
General partner interest	2.3	—
Total	$ 59.1	$ 6.2

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility. We borrow money under our credit facility to fund checks as they are presented. As of September 30, 2011, we had approximately $340.1 million of available borrowing capacity under this facility. Changes in drafts payable for the nine months ended September 30, 2011 and 2010 were as follows (in millions):

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Decrease in drafts payable	$ (0.1)	$ (5.2)

Working Capital Deficit. We had a working capital deficit of $1.1 million as of September 30, 2011. Changes in working capital may fluctuate significantly between periods even though our trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of our revenues are collected and a large volume of our gas purchases are paid near each month end

Table of Contents

or the first few days of the following month. As such, receivable and payable balances at any month end may fluctuate significantly depending on the timing of these receipts and payments. In addition, although we strive to minimize our natural gas and NGLs in inventory, these working inventory balances may fluctuate significantly from period to period due to operational reasons and due to changes in natural gas and NGL prices. Working capital also includes our mark to market derivative assets and liabilities associated with our commodity derivatives which may fluctuate significantly due to the changes in natural gas and NGL prices.

Off-Balance Sheet Arrangements. No off-balance sheet arrangements existed as of September 30, 2011.

Capital Requirements. During the nine months ended September 30, 2011, growth capital investments and investments in HEP were $ 53.4 million and $35.0 million, respectively, which were funded by internally generated cash flow and from borrowings under our credit facility. Our current capital spending projection for 2011 is approximately $132.1 million related to identified growth projects including $88.4 million incurred during the first nine months of 2011 (including the HEP investment). Our 2012 projected capital spend for growth capital is approximately $226.0 million which includes projected expenditures of $184.0 million for the pipeline expansion in Louisiana.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of September 30, 2011 is as follows (in millions):

	Payments Due by Period						
	Total	2011	2012	2013	2014	2015	Thereafter
Long-term debt obligations	$ 725.0	$ —	$ —	$ —	$ —	$ —	$ 725.0
Bank credit facility	75.0	—	—	—	—	—	75.0
Interest payable on fixed long-term debt obligations	417.2	—	64.3	64.3	64.3	64.3	160.0
Capital lease obligations	36.2	1.1	4.6	4.6	4.6	4.6	16.7
Operating lease obligations	37.4	3.1	12.8	7.1	5.3	3.9	5.2
Purchase obligations	2.1	2.1	—	—	—	—	—
Uncertain tax position obligations	3.8	3.8	—	—	—	—	—
Total contractual obligations	$ 1,296.7	$ 10.1	$ 81.7	$ 76.0	$ 74.2	$ 72.8	$ 981.9

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

Indebtedness

As of September 30, 2011 and December 31, 2010, long-term debt consisted of the following (in millions):

	September 30, 2011	December 31, 2010
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at September 30, 2011 and December 31, 2010 was 2.73% and 4.0%, respectively	$ 75.0	$ —
Senior unsecured notes (due 2018), net of discount of $12.1 million and $13.5 million, respectively, which bear interest at the rate of 8.875%	712.9	711.5
Series B secured note assumed in the Eunice transaction, which bore interest at the rate of 9.5%	—	7.1
	787.9	718.6
Less current portion	—	(7.1)
Debt classified as long-term	$ 787.9	$ 711.5

Credit Facility. On May 2, 2011 and July 11, 2011, we amended our bank credit facility. The May 2011 amendment increased our borrowing capacity from $420.0 million to $485.0 million, extended the maturity from February 2014 to May 2016, reduced our interest rates and improved terms of other covenants under the facility. The July 2011 amendment permitted Apache to have a first priority lien on certain assets that are associated with our joint interest arrangement with Apache and increased our ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under the credit agreement. See Note (2) to the condensed consolidated financial statements for a discussion of the amended terms.

As of September 30, 2011, our bank credit facility had a borrowing capacity of $485.0 million and there was $69.9 million in letters of credit issued and outstanding under the bank credit facility and $75.0 million of borrowings outstanding, leaving approximately $340.1 million available for future borrowing. The bank credit facility is guaranteed by substantially all of our subsidiaries. The bank credit facility matures in May 2016.

Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the nine months ended September 30, 2011, 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, 2010, and those set forth in Part II, “Item 1A. Risk Factors” of this report, if any, may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

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

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

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

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At September 30, 2011, we had $75.0 million in borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $0.8 million for the year.

At September 30, 2011, we had total fixed rate debt obligations of $712.9 million, consisting of our senior unsecured notes with an interest rate of 8.875%. The fair value of this fixed rate obligation was approximately $818.1 million as of September 30, 2011. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of such debt by $26.0 million.

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 and transportation 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,	
	2011	2010	2011	2010
Gathering and transportation margin	58.2%	65.4%	57.1%	62.8%
Gas processing margins:				
Processing margin	17.4%	9.6%	18.4%	12.1%
Percent of liquids	11.5%	9.8%	11.5%	10.9%
Fee based	12.9%	15.2%	13.0%	14.2%
Total gas processing	41.8%	34.6%	42.9%	37.2%
Total	100.0%	100.0%	100.0%	100.0%

We have hedges in place at September 30, 2011 covering a portion of the liquids volumes we expect to receive under percent of liquids (POL) contracts. The hedges done via swaps 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 2011 – December 2011	Ethane	32 (MBbls)	Index	$ 0.6328 /gal	$ (211)
October 2011 – December 2011	Propane	11 (MBbls)	Index	$ 1.2307 /gal	(129)
October 2011 – December 2011	Normal Butane	7 (MBbls)	Index	$ 1.5839 /gal	(74)
October 2011 – December 2011	Natural Gasoline	7 (MBbls)	Index	$ 1.8461 /gal	(94)
					$ (508)

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)
January 2012 – December 2012	Ethane	25 (MBbls)	Index	$ 0.4975 /gal	$ (184)
January 2012 – December 2012	Propane	73 (MBbls)	Index	$ 1.3005 /gal	(145)
January 2012 – December 2012	Normal Butane	39 (MBbls)	Index	$ 1.6855 /gal	(30)
January 2012 – December 2012	Natural Gasoline	30 (MBbls)	Index	$ 2.2664 /gal	226
					$ (133)

*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 56.2% of our hedgeable volumes at risk through December 2011 (24.0% of total volumes at risk through December 2011) via the use of swaps for our exposure related to propane, normal butane and natural gasoline. We have hedged our ethane exposure through December 2011 with a combination of swaps and puts that cover all of our total ethane volumes at risk. Of the total, 85.3% is covered by the puts. We have puts in place covering 74 MBbls of ethane for the final quarter of 2011 at an average price of $.4471/gallon. The net fair value asset of the puts as of September 30, 2011 was less than $0.1 million. We have also hedged 39.0% of our hedgeable volumes at risk for 2012 (21.3% of total volumes at risk for 2012).

We also have hedges in place at September 30, 2011 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 2011–December 2011	Ethane	16 (MBbls)	Index	$ 0.4538 /gal*	$ (228)
October 2011–December 2011	Propane	25 (MBbls)	Index	$ 1.2173 /gal*	(305)
October 2011–December 2011	Iso Butane	2 (MBbls)	Index	$ 1.5425 /gal*	(25)
October 2011–December 2011	Normal Butane	13 (MBbls)	Index	$ 1.6241 /gal*	(119)
October 2011–December 2011	Natural Gasoline	13 (MBbls)	Index	$ 2.1320 /gal*	(26)
October 2011–December 2011	Natural Gas	3,577 (MMBtu/d)	$ 4.7692 /MMBtu*	Index	(319)
					$ (1,022)

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (In thousands)
January 2012–December 2012	Ethane	28 (MBbls)	Index	$ 0.4980 /gal*	$ (201)
January 2012–December 2012	Propane	98 (MBbls)	Index	$ 1.3167 /gal*	(144)
January 2012–December 2012	Normal Butane	57 (MBbls)	Index	$ 1.7582 /gal*	123
January 2012–December 2012	Natural Gasoline	46 (MBbls)	Index	$ 2.3401 /gal*	487
January 2012–December 2012	Natural Gas	3,172 (MMBtu/d)	$ 4.8967 /MMBtu*	Index	(797)
					$ (532)

* weighted average

In relation to our fractionation spread risk, as set forth above, we have hedged 42.0% of our hedgeable liquids volumes at risk through December 31, 2011 (16.7% of total liquids volumes at risk) and 47.8% of the related hedgeable PTR volumes through December 31, 2011 (17.1% of total PTR volumes). We have also hedged 35.6% of our hedgeable liquids volumes at risk for 2012 (15.7% of total liquids volumes at risk) and 43.3% of the related hedgeable PTR volumes for 2012 (17.4% 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 5.4% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price.

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, 2011, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $2.2 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in an increase of approximately $2.6 million in the net fair value liability of these contracts as of September 30, 2011 to a net fair value liability of approximately $4.8 million.

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

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (September 30, 2011), 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, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. *Legal Proceedings*

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

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

Item 1A. *Risk Factors*

Information about risk factors for the three months ended September 30, 2011 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, 2010.

Table of Contents

Item 6. *Exhibits*

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

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
3.3	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.4	—	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008).
3.5	—	Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
3.6	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.8	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
3.10	—	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of January 19, 2010 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
4.1	—	Supplemental Indenture, dated as of July 11, 2011, to the indenture governing the Issuers' 8.875% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 11, 2011, filed with the Commission on July 12, 2011).
10.1	—	Second Amendment to Amended and Restated Credit Agreement dated as of July 11, 2011, 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 July 11, 2011, filed with the Commission on July 12, 2011).
10.2	—	Crosstex Energy Services, L.P. Severance Pay Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 1, 2011, filed with the Commission on July 1, 2011).

Table of Contents

Number		Description
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, 2011, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2011 and 2010, (ii) Condensed Consolidated Balance Sheets as of September 30, 2011 and December 31, 2010, (iii) Consolidated Statements of Cash Flows for the nine months ended September 30, 2011 and 2010, (iv) Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2011 and 2010, (v) Consolidated Statements of Changes in Partners' Equity for the quarter ended September 30, 2011, and (vi) the Notes to Condensed Consolidated Financial Statements.

* Filed herewith.
** Furnished herewith.

Table of Contents

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 4, 2011

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 4, 2011

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 4, 2011

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, 2011 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 4, 2011

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

November 4, 2011

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.