LINN ENERGY, LLC
Form 10-Q
October 25, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q

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

For the Quarterly Period Ended September 30, 2012

OR

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

for the transition period from _______________ to _______________

Commission File Number: 000-51719

LINN ENERGY, LLC
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	65-1177591 (IRS Employer Identification No.)
600 Travis, Suite 5100 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(281) 840-4000
(Registrant’s telephone number, including area code)

Indicate by check mark whether the 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 x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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.
Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

As of September 30, 2012, there were 199,645,612 units outstanding.

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GLOSSARY OF TERMS

As commonly used in the oil and natural gas industry and as used in this Quarterly Report on Form 10-Q, the following terms have the following meanings:

Bbl. One stock tank barrel or 42 United States gallons liquid volume.

Bcf. One billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Btu. One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 degrees to 59.5 degrees Fahrenheit.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

MBbls/d. MBbls per day.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent, determined using a ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcf/d. MMcf per day.

MMcfe. One million cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMcfe/d. MMcfe per day.

MMMBtu. One billion British thermal units.

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PART I – FINANCIAL INFORMATION
Item 1. Financial Statements
LINN ENERGY, LLC
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2012 (Unaudited)	December 31, 2011
	(in thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$1,154	$1,114
Accounts receivable – trade, net	436,132	284,565
Derivative instruments	324,300	255,063
Other current assets	74,788	80,734
Total current assets	836,374	621,476
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	11,255,246	7,835,650
Less accumulated depletion and amortization	(1,584,546)	(1,033,617)
	9,670,700	6,802,033
Other property and equipment	448,105	197,235
Less accumulated depreciation	(65,607)	(48,024)
	382,498	149,211
Derivative instruments	564,087	321,840
Other noncurrent assets	130,536	105,577
	694,623	427,417
Total noncurrent assets	10,747,821	7,378,661
Total assets	$11,584,195	$8,000,137
LIABILITIES AND UNITHOLDERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued expenses	$688,968	$403,450
Derivative instruments	2,564	14,060
Other accrued liabilities	169,394	75,898
Total current liabilities	860,926	493,408
Noncurrent liabilities:		
Credit facility	1,985,000	940,000
Senior notes, net	4,856,670	3,053,657
Derivative instruments	7,222	3,503
Other noncurrent liabilities	309,374	80,659
Total noncurrent liabilities	7,158,266	4,077,819
Commitments and contingencies (Note 10)		
Unitholders' capital:		

199,645,612 units and 177,364,558 units issued and outstanding at September 30, 2012, and December 31, 2011, respectively	3,086,568	2,751,354
Accumulated income	478,435	677,556
	3,565,003	3,428,910
Total liabilities and unitholders’ capital	$11,584,195	$8,000,137

The accompanying notes are an integral part of these condensed consolidated financial statements.

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LINN ENERGY, LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in thousands, except per unit amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$444,082	$292,482	$1,140,204	$835,579
Gains (losses) on oil and natural gas derivatives	(411,405)	824,240	30,273	660,279
Marketing revenues	12,323	1,477	24,454	4,159
Other revenues	3,328	1,284	8,084	3,564
	48,328	1,119,483	1,203,015	1,503,581
Expenses:				
Lease operating expenses	91,990	62,907	233,755	165,171
Transportation expenses	18,274	7,821	50,651	20,152
Marketing expenses	14,923	850	22,073	2,703
General and administrative expenses	45,166	29,891	129,672	91,994
Exploration costs	390	503	1,207	1,498
Bad debt expenses	30	79	8	74
Depreciation, depletion and amortization	167,695	88,328	428,477	234,039
Impairment of long-lived assets	—	—	146,499	—
Taxes, other than income taxes	37,885	20,875	93,736	56,920
(Gains) losses on sale of assets and other, net	(14)	279	1,500	1,870
	376,339	211,533	1,107,578	574,421
Other income and (expenses):				
Loss on extinguishment of debt	—	—	—	(94,372)
Interest expense, net of amounts capitalized	(105,697)	(65,848)	(277,606)	(191,673)
Other, net	(1,247)	(1,613)	(12,472)	(6,331)
	(106,944)	(67,461)	(290,078)	(292,376)
Income (loss) before income taxes	(434,955)	840,489	(194,641)	636,784
Income tax benefit (expense)	4,950	(2,862)	(4,480)	(8,730)
Net income (loss)	$(430,005)	$837,627	$(199,121)	$628,054
Net income (loss) per unit:				
Basic	$(2.18)	$4.74	$(1.04)	$3.63
Diluted	$(2.18)	$4.72	$(1.04)	$3.62
Weighted average units outstanding:				
Basic	197,675	174,956	196,152	171,076
Diluted	197,675	175,644	196,152	171,825
Distributions declared per unit	$0.725	$0.69	$2.14	$2.01

The accompanying notes are an integral part of these condensed consolidated financial statements.

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LINN ENERGY, LLC
CONDENSED CONSOLIDATED STATEMENT OF UNITHOLDERS' CAPITAL
(Unaudited)

	Units	Unitholders' Capital	Accumulated Income	Total Unitholders' Capital
	(in thousands)			
December 31, 2011	177,365	$2,751,354	$677,556	$3,428,910
Sale of units, net of underwriting discounts and expenses of $30,102	21,090	731,360	—	731,360
Issuance of units	1,191	5,711	—	5,711
Distributions to unitholders		(426,918)	—	(426,918)
Unit-based compensation expenses		21,735	—	21,735
Excess tax benefit from unit-based compensation		3,326	—	3,326
Net loss		—	(199,121)	(199,121)
September 30, 2012	199,646	$3,086,568	$478,435	$3,565,003

The accompanying notes are an integral part of these condensed consolidated financial statements.

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LINN ENERGY, LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2012	2011
	(in thousands)	
Cash flow from operating activities:		
Net income (loss)	$(199,121)	$628,054
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	428,477	234,039
Impairment of long-lived assets	146,499	—
Unit-based compensation expenses	21,735	16,759
Loss on extinguishment of debt	—	94,372
Amortization and write-off of deferred financing fees and other	21,453	17,910
Gains on sale of assets and other, net	(485)	(61)
Deferred income tax	965	4,832
Mark-to-market on derivatives:		
Total gains	(30,273)	(660,279)
Cash settlements	294,446	162,876
Cash settlements on canceled derivatives	—	26,752
Premiums paid for derivatives	(583,434)	(59,948)
Changes in assets and liabilities:		
Increase in accounts receivable – trade, net	(138,171)	(70,476)
(Increase) decrease in other assets	(2,242)	4,968
Increase in accounts payable and accrued expenses	94,762	78,870
Increase in other liabilities	89,820	7,761
Net cash provided by operating activities	144,431	486,429
Cash flow from investing activities:		
Acquisition of oil and natural gas properties	(2,487,767)	(846,976)
Development of oil and natural gas properties	(710,360)	(383,655)
Purchases of other property and equipment	(38,090)	(37,419)
Proceeds from sale of properties and equipment and other	1,438	10,776
Net cash used in investing activities	(3,234,779)	(1,257,274)
Cash flow from financing activities:		
Proceeds from sale of units	761,362	649,586
Proceeds from borrowings	4,929,802	1,514,240
Repayments of debt	(2,085,000)	(1,154,679)
Distributions to unitholders	(426,918)	(344,612)
Financing fees, offering expenses and other, net	(92,184)	(109,751)
Excess tax benefit from unit-based compensation	3,326	3,326
Purchase of units	—	(13,191)
Net cash provided by financing activities	3,090,388	544,919
Net increase (decrease) in cash and cash equivalents	40	(225,926)
Cash and cash equivalents:		

Beginning	1,114	236,001
Ending	$1,154	$10,075

The accompanying notes are an integral part of these condensed consolidated financial statements.

LINN ENERGY, LLC
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
Note 1 – Basis of Presentation

Nature of Business

Linn Energy, LLC ("LINN Energy" or the "Company") is an independent oil and natural gas company. LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. The Company's properties are located in the United States ("U.S."), in the Mid-Continent, the Hugoton Basin, the Green River Basin, the Permian Basin, Michigan, Illinois, the Williston/Powder River Basin, California and east Texas. Effective January 1, 2012, the Company realigned its existing regions. The realignment had no effect on the Company's operations. The Company added the East Texas region in May 2012 and the Green River Basin region in July 2012, and currently has eight operating regions in the U.S.: Mid-Continent, which includes properties in Oklahoma, Louisiana and the eastern portion of the Texas Panhandle (including the Granite Wash and Cleveland horizontal plays); Hugoton Basin, which includes properties located primarily in Kansas and the Shallow Texas Panhandle; Green River Basin, which includes properties located in southwest Wyoming; Permian Basin, which includes areas in west Texas and southeast New Mexico; Michigan/Illinois, which includes the Antrim Shale formation in the northern part of Michigan and oil properties in southern Illinois; Williston/Powder River Basin, which includes the Bakken formation in North Dakota and the Powder River Basin in Wyoming; California, which includes the Brea Olinda Field of the Los Angeles Basin; and East Texas, which includes properties located in east Texas.

Principles of Consolidation and Reporting

The condensed consolidated financial statements at September 30, 2012, and for the three months and nine months ended September 30, 2012, and September 30, 2011, are unaudited, but in the opinion of management include all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted under Securities and Exchange Commission ("SEC") rules and regulations; as such, this report should be read in conjunction with the financial statements and notes in the Company's Annual Report on Form 10-K for the year ended December 31, 2011. The results reported in these unaudited condensed consolidated financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

The condensed consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated upon consolidation. Investments in noncontrolled entities over which the Company exercises significant influence are accounted for under the equity method.

The condensed consolidated financial statements for previous periods include certain reclassifications that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income (loss) or unitholders' capital.

Use of Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses. The estimates that are particularly significant to the

financial statements include estimates of the Company’s reserves of oil, natural gas and natural gas liquids (“NGL”), future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and operating expenses, fair values of commodity derivatives and fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management’s best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As
future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Recently Issued Accounting Standards

In December 2011, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") that requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The ASU requires disclosure of both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The ASU will be applied retrospectively and is effective for periods beginning on or after January 1, 2013. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements and related disclosures.

In May 2011, the FASB issued an ASU that further addresses fair value measurement accounting and related disclosure requirements. The ASU clarifies the FASB's intent regarding the application of existing fair value measurement and disclosure requirements, changes the fair value measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair value measurements. The ASU is to be applied prospectively and is effective for periods beginning after December 15, 2011. The Company adopted the ASU effective January 1, 2012. The adoption of the requirements of the ASU, which expanded disclosures, had no effect on the Company's results of operations or financial position.

Note 2 – Acquisitions

Acquisitions – 2012

On July 31, 2012, the Company completed the acquisition of certain oil and natural gas properties in the Jonah Field located in the Green River Basin of southwest Wyoming from BP America Production Company ("BP"). The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid approximately $990 million in total consideration for these properties. The transaction was financed with borrowings under the Company's Credit Facility, as defined in Note 6.

On May 1, 2012, the Company completed the acquisition of certain oil and natural gas properties located in east Texas. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid approximately $168 million in total consideration for these properties. The transaction was financed with borrowings under the Company's Credit Facility.

On April 3, 2012, the Company entered into a joint-venture agreement ("Agreement") with an affiliate of Anadarko Petroleum Corporation ("Anadarko") whereby the Company participates as a partner in the CO_2 enhanced oil recovery development of the Salt Creek Field, located in the Powder River Basin of Wyoming. Anadarko assigned the Company 23% of its interest in the field in exchange for future funding of $400 million of Anadarko's development costs. The results of operations of these properties have been included in the condensed consolidated financial statements since the Agreement date. The Company assigned approximately $392 million to the net assets acquired as of the Agreement date, which reflects an imputed discount of approximately $8 million on the future funding of this transaction. As of September 30, 2012, the Company has paid approximately $119 million towards the future funding commitment.

On March 30, 2012, the Company completed the acquisition of certain oil and natural gas properties located in the Hugoton Basin in Kansas from BP. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid approximately $1.16 billion in total consideration for these properties. The transaction was financed primarily with proceeds from the March 2012 debt offering (see Note 6).

During the nine months ended September 30, 2012, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition dates. The Company, in the aggregate, paid approximately $52 million in total consideration for these properties.

These acquisitions were accounted for under the acquisition method of accounting. Accordingly, the Company conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisitions were expensed as incurred. The initial accounting for the business combinations is not complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition dates.

The following presents the values assigned to the net assets acquired as of the acquisition dates (in thousands):

Assets:	
Current	$9,083
Noncurrent	209,038
Oil and natural gas properties	2,636,289
Total assets acquired	$2,854,410
Liabilities:	
Current	$223,286
Asset retirement obligations	63,896
Noncurrent	196,601
Total liabilities assumed	$483,783
Net assets acquired	$2,370,627

Current assets include receivables and inventory and noncurrent assets include other property and equipment. Current liabilities include payables, ad valorem taxes payable and environmental liabilities. Current liabilities and noncurrent liabilities, as of the Agreement date, consist of payables of approximately $195 million and $197 million, respectively, related to the future funding commitment associated with the Anadarko transaction discussed above. As of September 30, 2012, the Company has paid approximately $119 million towards this commitment.

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

The revenues and expenses related to certain properties acquired from BP, Plains Exploration & Production Company ("Plains"), Panther Energy Company, LLC and Red Willow Mid-Continent, LLC (collectively referred to as "Panther"), SandRidge Exploration and Production, LLC ("SandRidge") and an affiliate of Concho Resources Inc. ("Concho") are included in the condensed consolidated results of operations of the Company as of July 31, 2012 (BP Green River Basin acquisition), March 30, 2012 (BP Hugoton Basin acquisition), December 15, 2011 (Plains acquisition), June 1, 2011 (Panther acquisition), April 1, 2011 (SandRidge acquisition), and March 31, 2011 (Concho acquisition). The following unaudited pro forma financial information presents a summary of the Company's condensed consolidated results of operations for the three months and nine months ended September 30, 2012, and September 30, 2011, assuming the acquisitions from BP had been completed as of January 1, 2011, and the acquisitions from Plains, Panther, SandRidge and Concho had been completed as of January 1, 2010, including adjustments to reflect the values assigned to the net assets acquired. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of these dates.

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LINN ENERGY, LLC
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands, except per unit amounts)			
Total revenues and other	$68,171	$1,330,182	$1,366,395	$2,134,415
Total operating expenses	$388,555	$322,562	$1,243,979	$927,797
Net income (loss)	$(424,214)	$908,390	$(204,373)	$811,912
Net income (loss) per unit:				
Basic	$(2.15)	$5.14	$(1.06)	$4.70
Diluted	$(2.15)	$5.12	$(1.06)	$4.68

Acquisitions – 2011

On June 1, 2011, the Company completed the acquisition of certain oil and natural gas properties in the Cleveland play, located in the Texas Panhandle, from Panther. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid approximately $224 million in total consideration for these properties. The transaction was financed primarily with proceeds from the Company’s May 2011 debt offering.

On May 2, 2011, and May 11, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Williston Basin. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition dates. The Company paid approximately $153 million in total consideration for these acquisitions. The transactions were financed initially with borrowings under the Company’s Credit Facility.

On April 1, 2011, and April 5, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin, including properties from SandRidge. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition dates. The Company paid approximately $239 million in total consideration for these acquisitions. The transactions were financed initially with borrowings under the Company’s Credit Facility.

On March 31, 2011, the Company completed the acquisition of certain oil and natural gas properties in the Williston Basin from Concho. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid $194 million in cash and recorded a receivable from Concho of $2 million, resulting in total consideration for the acquisition of approximately $192 million. The transaction was financed primarily with proceeds from the Company’s March 2011 public offering of units, as described below.

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LINN ENERGY, LLC
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued
(Unaudited)

Note 3 – Unitholders' Capital

Equity Distribution Agreement

In August 2011, the Company entered into an equity distribution agreement, pursuant to which it may from time to time issue and sell units representing limited liability company interests having an aggregate offering price of up to $500 million. Sales of units, if any, will be made through a sales agent by means of ordinary brokers' transactions, in block transactions, or as otherwise agreed with the agent. The Company expects to use the net proceeds from any sale of the units for general corporate purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

In January 2012, the Company, under its equity distribution agreement, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $2 million in commissions and professional service expenses). The Company used the net proceeds for general corporate purposes, including the repayment of a portion of the indebtedness outstanding under its Credit Facility. In September 2011, the Company, under its equity distribution agreement, issued and sold 16,060 units representing limited liability company interests at an average unit price of $38.25 for proceeds of approximately $602,000 (net of approximately $12,000 in commissions). The Company used the net proceeds for general corporate purposes. At September 30, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

Public Offering of Units

In January 2012, the Company sold 19,550,000 units representing limited liability company interests at $35.95 per unit ($34.512 per unit, net of underwriting discount) for net proceeds of approximately $674 million (after underwriting discount and offering expenses of approximately $28 million). The Company used the net proceeds from the sale of these units to repay a portion of the outstanding indebtedness under its Credit Facility.

In March 2011, the Company sold 16,726,067 units representing limited liability company interests at $38.80 per unit ($37.248 per unit, net of underwriting discount) for net proceeds of approximately $623 million (after underwriting discount and offering expenses of approximately $26 million). The Company used a portion of the net proceeds from the sale of these units to fund the March 2011 redemptions of a portion of the outstanding 2017 Senior Notes and 2018 Senior Notes, and to fund the cash tender offers and related expenses for a portion of the remaining 2017 Senior Notes and 2018 Senior Notes (see Note 6). The Company used the remaining net proceeds from the sale of units to finance a portion of the March 31, 2011, acquisition in the Williston/Powder River Basin region.

LinnCo Initial Public Offering – Subsequent Event

On October 17, 2012, LinnCo, LLC ("LinnCo"), a wholly owned subsidiary of LINN Energy at September 30, 2012, completed its initial public offering (the "LinnCo IPO") of 34,787,500 of its common shares representing limited liability company interests at a price to the public of $36.50 per share ($34.858 per share, net of underwriting discount and structuring fee) for net proceeds of approximately $1.2 billion (after underwriting discount and structuring fee of approximately $57 million). The net proceeds LinnCo received from the offering were used to acquire 34,787,500 LINN Energy units which are equal to the number of LinnCo shares sold in the offering. The Company used the proceeds from the sale of the units to LinnCo to pay the expenses of the offering and repay a portion of the outstanding indebtedness under its Credit Facility.

Unit Repurchase Plan

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100 million of the Company’s outstanding units from time to time on the open market or in negotiated purchases. In August 2011, the Company repurchased 400,000 units at an average unit price of $32.98 for a total cost of approximately $13 million. All units were subsequently canceled. At September 30, 2012, approximately $56 million was available for unit repurchase under the program. The timing and amounts of any such repurchases will be at the discretion of management, subject to market conditions and other factors, and in accordance with applicable securities laws and other legal requirements. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. Units are acquired at fair market value on the date of repurchase.

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LINN ENERGY, LLC
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued
(Unaudited)

Distributions

Under the Company's limited liability company agreement, the Company's unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. Distributions paid by the Company during the nine months ended September 30, 2012, are presented on the condensed consolidated statement of unitholders' capital. On April 24, 2012, the Company's Board of Directors approved an increase in the quarterly cash distribution from $0.69 per unit to $0.725 per unit with respect to the first quarter of 2012, representing an increase of 5%. On October 23, 2012, the Company's Board of Directors declared a cash distribution of $0.725 per unit with respect to the third quarter of 2012. The distribution, totaling approximately $170 million, will be paid on November 14, 2012, to unitholders of record as of the close of business on November 6, 2012.

Note 4 – Oil and Natural Gas Properties

Oil and Natural Gas Capitalized Costs

Aggregate capitalized costs related to oil, natural gas and NGL production activities with applicable accumulated depletion and amortization are presented below:

	September 30, 2012	December 31, 2011
	(in thousands)	
Proved properties:		
Leasehold acquisition	$8,643,542	$6,040,239
Development	2,263,183	1,484,486
Unproved properties	348,521	310,925
	11,255,246	7,835,650
Less accumulated depletion and amortization	(1,584,546)	(1,033,617)
	$9,670,700	$6,802,033

Impairment of Proved Properties

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

Based on the analysis described above, for the nine months ended September 30, 2012, the Company recorded a noncash impairment charge, before and after tax, of approximately $146 million associated with proved oil and natural gas properties related to lower commodity prices. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair-value measurement. The charge is included in "impairment of long-lived assets" on the condensed consolidated statements of operations. The Company recorded no impairment charge of proved oil and natural gas properties for the three months ended September 30, 2012, or three months or nine months ended September 30, 2011.

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Note 5 – Unit-Based Compensation

During the nine months ended September 30, 2012, the Company granted an aggregate 1,009,883 restricted units to employees, primarily as part of its annual review of employee compensation, with an aggregate fair value of approximately $38 million. The restricted units vest over three years. A summary of unit-based compensation expenses included on the condensed consolidated statements of operations is presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
General and administrative expenses	$6,505	$5,320	$20,416	$16,014
Lease operating expenses	396	258	1,319	745
Total unit-based compensation expenses	$6,901	$5,578	$21,735	$16,759
Income tax benefit	$2,550	$2,061	$8,031	$6,192

Note 6 – Debt

The following summarizes debt outstanding:

	September 30, 2012		December 31, 2011	
	Carrying Value	Fair Value (1)	Carrying Value	Fair Value (1)
	(in millions, except percentages)			
Credit facility (2)	$1,985	$1,985	$940	$940
11.75% senior notes due 2017	41	45	41	46
9.875% senior notes due 2018	14	16	14	16
6.50% senior notes due May 2019	750	747	750	742
6.25% senior notes due November 2019	1,800	1,784	—	—
8.625% senior notes due 2020	1,300	1,419	1,300	1,406
7.75% senior notes due 2021	1,000	1,054	1,000	1,036
Less current maturities	—	—	—	—
	6,890	$7,050	4,045	$4,186
Unamortized discount	(48)		(51)	
Total debt, net of discount	$6,842		$3,994	

(1) The carrying value of the Credit Facility is estimated to be substantially the same as its fair value. Fair values of the senior notes were estimated based on prices quoted from third-party financial institutions, which are characteristic of Level 2 fair value measurement inputs.

(2) Variable interest rates of 2.22% and 2.57% at September 30, 2012, and December 31, 2011, respectively.

Credit Facility

The Company's Fifth Amended and Restated Credit Agreement ("Credit Facility") provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount. In October 2011, as part of the semi-annual redetermination, a borrowing base of $3.0 billion was approved by the lenders with a maximum commitment amount of $1.5 billion. In February 2012, lenders approved an increase in the maximum commitment amount to $2.0 billion. In May 2012, the Company entered into an amendment to its Credit Facility to increase the borrowing base to $3.5 billion and extend the maturity date from April 2016 to April 2017. In July 2012, the Company entered into an amendment to its Credit Facility to increase the maximum commitment amount from $2.0 billion to $3.0 billion. In September 2012, the Company entered into an amendment and consent to its Credit Facility to permit the LinnCo IPO and to exclude the Company's subsidiary, LinnCo, from the restrictive covenants under the Credit Facility.

During the nine months ended September 30, 2012, in connection with amendments to its Credit Facility, the Company incurred financing fees and expenses of approximately $12 million, which will be amortized over the life of the Credit Facility. Such amortized expenses are recorded in "interest expense, net of amounts capitalized" on the condensed consolidated statements of operations.

At September 30, 2012, available borrowing capacity under the Credit Facility was approximately $1.0 billion, which includes a $5 million reduction in availability for outstanding letters of credit.

Redetermination of the borrowing base under the Credit Facility, based primarily on reserve reports that reflect commodity prices at such time, occurs semi-annually, in April and October, as well as upon requested interim redeterminations, by the lenders at their sole discretion. The Company also has the right to request one additional borrowing base redetermination per year at its discretion, as well as the right to an additional redetermination each year in connection with certain acquisitions. Significant declines in commodity prices may result in a decrease in the borrowing base. The Company's obligations under the Credit Facility are secured by mortgages on its and certain of its material subsidiaries' oil and natural gas properties and other personal property as well as a pledge of all ownership interests in its direct and indirect material subsidiaries. The Company is required to maintain either: 1) mortgages on properties representing at least 80% of the total value of oil and natural gas properties included on the most recent reserve report, or 2) a Collateral Coverage Ratio of at least 2.5 to 1. Collateral Coverage Ratio is defined as the ratio of the present value of future cash flows from proved reserves from the currently mortgaged properties to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount. Additionally, the obligations under the Credit Facility are guaranteed by all of the Company's material subsidiaries other than LinnCo and are required to be guaranteed by any future material subsidiaries.

At the Company's election, interest on borrowings under the Credit Facility is determined by reference to either the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.5% and 2.5% per annum (depending on the then-current level of borrowings under the Credit Facility) or the alternate base rate ("ABR") plus an applicable margin between 0.5% and 1.5% per annum (depending on the then-current level of borrowings under the Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the ABR and at the end of the applicable interest period for loans bearing interest at LIBOR. The Company is required to pay a commitment fee to the lenders under the Credit Facility, which accrues at a rate per annum between 0.375% and 0.5% on the average daily unused amount of the lesser of: (i) the maximum commitment amount of the lenders and (ii) the then-effective borrowing base. The Company is in compliance with all financial and other covenants of the Credit Facility.

Senior Notes Due November 2019

On March 2, 2012, the Company issued $1.8 billion in aggregate principal amount of 6.25% senior notes due November 2019 ("November 2019 Senior Notes") at a price of 99.989%. The November 2019 Senior Notes were sold to a group of initial purchasers and then resold to qualified institutional buyers, each in transactions exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"). The Company received net proceeds of approximately $1.77 billion (after deducting the initial purchasers' discount of $198,000 and offering expenses of approximately $29 million). The Company used the net proceeds to fund the BP acquisition (see Note 2). The remaining proceeds were used to repay indebtedness under the Company's Credit Facility and for general corporate purposes. The financing fees and expenses of approximately $29 million incurred in connection with the November 2019 Senior Notes will be amortized over the life of the notes. Such amortized financing fees and expenses are recorded in "interest expense, net of amounts capitalized" on the condensed consolidated statements of operations.

The November 2019 Senior Notes were issued under an indenture dated March 2, 2012 ("November 2019 Indenture"), mature November 1, 2019, and bear interest at 6.25%. Interest is payable semi-annually on May 1 and November 1, beginning November 1, 2012. The November 2019 Senior Notes are general unsecured senior obligations of the Company and are effectively junior in right of payment to any secured indebtedness of the Company to the extent of the collateral securing such indebtedness. Each of the Company's material subsidiaries has guaranteed the November

2019 Senior Notes on a senior unsecured basis. The November 2019 Indenture provides that the Company may redeem: (i) on or prior to November 1, 2015, up to 35% of the aggregate principal amount of the November 2019 Senior Notes at a redemption price of 106.25% of the principal amount redeemed, plus accrued and unpaid interest, with the net cash proceeds of one or more equity offerings;

(ii) prior to November 1, 2015, all or part of the November 2019 Senior Notes at a redemption price equal to the principal amount redeemed, plus a make-whole premium (as defined in the November 2019 Indenture) and accrued and unpaid interest; and (iii) on or after November 1, 2015, all or part of the November 2019 Senior Notes at a redemption price equal to 103.125%, and decreasing percentages thereafter, of the principal amount redeemed, plus accrued and unpaid interest. The November 2019 Indenture also provides that, if a change of control (as defined in the November 2019 Indenture) occurs, the holders have a right to require the Company to repurchase all or part of the November 2019 Senior Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The November 2019 Indenture contains covenants substantially similar to those under the Company's May 2019 Senior Notes, 2010 Issued Senior Notes and Original Senior Notes, as defined below, that, among other things, limit the Company's ability to: (i) pay distributions on, purchase or redeem the Company's units or redeem its subordinated debt; (ii) make investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create certain liens; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of the Company's assets; (vii) enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. The Company is in compliance with all financial and other covenants of the November 2019 Senior Notes.

In connection with the issuance and sale of the November 2019 Senior Notes, the Company entered into a Registration Rights Agreement ("November 2019 Registration Rights Agreement") with the initial purchasers. Under the November 2019 Registration Rights Agreement, the Company agreed to use its reasonable efforts to file with the SEC and cause to become effective a registration statement relating to an offer to issue new notes having terms substantially identical to the November 2019 Senior Notes in exchange for outstanding November 2019 Senior Notes within 400 days after the notes were issued. In certain circumstances, the Company may be required to file a shelf registration statement to cover resales of the November 2019 Senior Notes. If the Company fails to satisfy these obligations, the Company may be required to pay additional interest to holders of the November 2019 Senior Notes under certain circumstances.

Senior Notes Due May 2019

On May 13, 2011, the Company issued $750 million in aggregate principal amount of 6.50% senior notes due 2019 (the "May 2019 Senior Notes"). The indentures related to the May 2019 Senior Notes contain redemption provisions and covenants that are substantially similar to those of the November 2019 Senior Notes. On May 8, 2012, the Company filed a registration statement on Form S-4 to register exchange notes that are also substantially similar to the November 2019 Senior Notes. On September 24, 2012, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $750 million outstanding principal amount of May 2019 Senior Notes for an equal amount of new May 2019 Senior Notes.

The terms of the new May 2019 Senior Notes are identical in all material respects to those of the outstanding May 2019 Senior Notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the outstanding May 2019 Senior Notes do not apply to the new May 2019 Senior Notes. The exchange offer expired on October 23, 2012. Pursuant to the terms of the registration rights agreement entered into in connection with the May 2019 Senior Notes, the Company agreed to use its reasonable efforts to cause the registration statement relating to the new May 2019 Senior Notes to become effective within 400 days after the notes were issued. The effective date of the registration statement was past the deadline in the registration rights agreement, and therefore, the Company will be required to pay additional interest of approximately $850,000 to holders of the May 2019 Senior Notes on the next interest payment date of November 15, 2012.

Senior Notes Due 2020 and Senior Notes Due 2021

The Company has $1.3 billion in aggregate principal amount of 8.625% senior notes due 2020 (the “2020 Senior Notes”) and $1.0 billion in aggregate principal amount of 7.75% senior notes due 2021 (the “2021 Senior Notes,” and together with the 2020 Senior Notes, the “2010 Issued Senior Notes”). The indentures related to the 2010 Issued Senior Notes contain redemption provisions and covenants that are substantially similar to those of the November 2019 Senior Notes. However, in 2011, the Company caused the trustee to remove the restrictive legends from each of the 2010 Issued Senior Notes making them freely tradable (other than with respect to persons that are affiliates of the Company), thereby terminating the Company’s obligations under each of the registration rights agreements entered into in connection with the issuance of the 2010 Issued Senior Notes.

Senior Notes Due 2017 and Senior Notes Due 2018

The Company also has $41 million (originally $250 million) in aggregate principal amount of 11.75% senior notes due 2017 (the “2017 Senior Notes”) and $14 million (originally $256 million) in aggregate principal amount of 9.875% senior notes due 2018 (the “2018 Senior Notes” and together with the 2017 Senior Notes, the “Original Senior Notes”). The indentures related to the Original Senior Notes initially contained redemption provisions and covenants that were substantially similar to those of the November 2019 Senior Notes; however, in conjunction with the tender offers in 2011, the indentures were amended and most of the covenants and certain default provisions were eliminated. The amendments became effective upon the execution of the supplemental indentures to the indentures governing the Original Senior Notes.

In March 2011 and June 2011, in accordance with the indentures related to the Original Senior Notes, the Company redeemed and also repurchased through cash tender offers, a portion of the Original Senior Notes. In connection with the redemptions and cash tender offers of a portion of the Original Senior Notes, the Company recorded a loss on extinguishment of debt of approximately $94 million for the nine months ended September 30, 2011.

Note 7 – Derivatives

Commodity Derivatives

The Company utilizes derivative instruments to minimize the variability in cash flow due to commodity price movements. The Company has historically entered into derivative instruments such as swap contracts, put options and collars to economically hedge its forecasted oil, natural gas and NGL sales. The Company did not designate any of these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 8 for fair value disclosures about oil and natural gas commodity derivatives.

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The following table summarizes derivative positions for the periods indicated as of September 30, 2012:

	October 1 – December 31, 2012	2013	2014	2015	2016	2017
Natural gas positions:						
Fixed price swaps:						
Hedged volume (MMMBtu)	22,623	87,290	97,401	118,041	121,841	120,122
Average price ($/MMBtu)	$5.12	$5.22	$5.25	$5.19	$4.20	$4.26
Puts: (1)						
Hedged volume (MMMBtu)	19,979	86,198	79,628	71,854	76,269	66,886
Average price ($/MMBtu)	$5.40	$5.37	$5.00	$5.00	$5.00	$4.88
Total:						
Hedged volume (MMMBtu)	42,602	173,488	177,029	189,895	198,110	187,008
Average price ($/MMBtu)	$5.25	$5.29	$5.14	$5.12	$4.51	$4.48
Oil positions:						
Fixed price swaps: (2)						
Hedged volume (MBbls)	2,396	11,871	11,903	11,599	11,464	4,755
Average price ($/Bbl)	$96.54	$94.97	$92.92	$96.23	$90.56	$89.02
Puts:						
Hedged volume (MBbls)	634	3,105	3,960	3,426	3,271	384
Average price ($/Bbl)	$99.19	$97.86	$91.30	$90.00	$90.00	$90.00
Total:						
Hedged volume (MBbls)	3,030	14,976	15,863	15,025	14,735	5,139
Average price ($/Bbl)	$97.09	$95.57	$92.52	$94.81	$90.44	$89.10
Natural gas basis differential positions: (3)						
Panhandle basis swaps:						
Hedged volume (MMMBtu)	18,768	77,800	79,388	87,162	19,764	—
Hedged differential ($/MMBtu)	$(0.55)	$(0.56)	$(0.33)	$(0.33)	$(0.31)	$—
NWPL - Rockies basis swaps:						
Hedge volume (MMMBtu)	8,492	34,785	36,026	38,362	39,199	—
Hedge differential ($/MMBtu)	$(0.20)	$(0.20)	$(0.20)	$(0.20)	$(0.20)	$—
MichCon basis swaps:						
Hedged volume (MMMBtu)	2,447	9,600	9,490	9,344	—	—
Hedged differential ($/MMBtu)	$0.12	$0.10	$0.08	$0.06	$—	$—
Houston Ship Channel basis swaps:						
Hedged volume (MMMBtu)	1,573	5,731	5,256	4,891	4,575	—
Hedged differential ($/MMBtu)	$(0.10)	$(0.10)	$(0.10)	$(0.10)	$(0.10)	$—
Permian basis swaps:						
Hedged volume (MMMBtu)	1,141	4,636	4,891	5,074	—	—

Hedged differential ($/MMBtu)	$(0.19)	$(0.20)	$(0.21)	$(0.21)	$—	$—
Oil timing differential positions:						
Trade month roll swaps: [4]						
Hedged volume (MBbls)	1,642	6,944	7,254	7,251	7,446	6,486
Hedged differential ($/Bbl)	$0.21	$0.22	$0.22	$0.24	$0.25	$0.25

(1) Includes certain outstanding natural gas puts of approximately 2,664 MMMBtu for the period October 1, 2012, through December 31, 2012, 10,570 MMMBtu for each of the years ending December 31, 2013, December 31, 2014, and December 31, 2015, and 10,599 MMMBtu for the year ending December 31, 2016, used to hedge revenues associated with NGL production.

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(2) Includes certain outstanding fixed price oil swaps of approximately 5,384 MBbls which may be extended annually at a price of $100.00 per Bbl for each of the years ending December 31, 2017, and December 31, 2018, and $90.00 per Bbl for the year ending December 31, 2019, if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.

(3) Settle on the respective pricing index to hedge basis differential associated with natural gas production.

(4) The Company hedges the timing risk associated with the sales price of oil in the Mid-Continent, Hugoton Basin and Permian Basin regions. In these regions, the Company generally sells oil for the delivery month at a sales price based on the average NYMEX price of light crude oil during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is prompt (the “trade month roll”).

During the nine months ended September 30, 2012, the Company entered into commodity derivative contracts consisting of oil and natural gas swaps and puts for 2012 through 2017, and paid premiums for put options of approximately $583 million. Also during the nine months ended September 30, 2012, the Company entered into natural gas basis swaps for 2012 through 2016 and trade month roll swaps for 2012 through 2017. In October 2012, the Company entered into natural gas swaps for 2018.

Settled derivatives on natural gas production for the three months and nine months ended September 30, 2012, included volumes of 40,202 MMMBtu and 98,282 MMMBtu, respectively, at average contract prices of $5.31 per MMBtu and $5.49 per MMBtu. Settled derivatives on oil production for the three months and nine months ended September 30, 2012, included volumes of 2,951 MBbls and 8,259 MBbls, respectively, at average contract prices of $97.44 per Bbl and $97.80 per Bbl. Settled derivatives on natural gas production for the three months and nine months ended September 30, 2011, included volumes of 16,140 MMMBtu and 48,317 MMMBtu, respectively, at an average contract price of $8.24 per MMBtu. Settled derivatives on oil production for the three months and nine months ended September 30, 2011, included volumes of 2,123 MBbls and 5,794 MBbls, respectively, at average contract prices of $87.10 per Bbl and $85.19 per Bbl. The natural gas derivatives are settled based on the closing price of NYMEX natural gas on the last trading day for the delivery month, which occurs on the third business day preceding the delivery month, or the relevant index prices of natural gas published in Inside FERC’s Gas Market Report on the first business day of the delivery month. The oil derivatives are settled based on the average closing price of NYMEX light crude oil for each day of the delivery month.

Balance Sheet Presentation

The Company’s commodity derivatives are presented on a net basis in “derivative instruments” on the condensed consolidated balance sheets. The following summarizes the fair value of derivatives outstanding on a gross basis:

	September 30, 2012	December 31, 2011
	(in thousands)	
Assets:		
Commodity derivatives	$1,302,008	$880,175
Liabilities:		
Commodity derivatives	$423,407	$320,835

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company’s counterparties are current participants or affiliates of participants in its Credit Facility or were participants or affiliates of participants in its Credit Facility at the time it originally entered into the derivatives. The Credit Facility is secured by the Company’s oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The maximum amount of loss due to credit risk that the Company would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $1.3 billion at September 30, 2012. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company’s minimum credit quality standard, or have a guarantee from an affiliate that meets the Company’s minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company’s counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss is somewhat mitigated.

Gains (Losses) on Derivatives

Gains and losses on derivatives, including realized and unrealized gains and losses, are reported on the condensed consolidated statements of operations in "gains (losses) on oil and natural gas derivatives." Realized gains (losses), excluding canceled derivatives, represent amounts related to the settlement of derivative instruments and are aligned with the underlying production. Unrealized gains (losses) represent the change in fair value of the derivative instruments and are noncash items.

The following presents the Company's reported gains and losses on derivative instruments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Realized gains:				
Commodity derivatives	$108,602	$65,036	$281,597	$162,926
Canceled derivatives	—	26,752	—	26,752
Recovery of bankruptcy claim (see Note 10)	—	—	18,277	—
	108,602	91,788	299,874	189,678
Unrealized gains (losses):				
Commodity derivatives	(520,007)	732,452	(269,601)	470,601
Total gains (losses):				
Total	$(411,405)	$824,240	$30,273	$660,279

Note 8 – Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity derivatives at fair value (see Note 7) on a recurring basis. The Company uses certain pricing models to determine the fair value of its derivative financial instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company's commodity derivatives.

The following presents the fair value hierarchy for assets and liabilities measured at fair value on a recurring basis:

	September 30, 2012		
	Level 2	Netting [1]	Total
	(in thousands)		
Assets:			
Commodity derivatives	$1,302,008	$(413,621)	$888,387
Liabilities:			
Commodity derivatives	$423,407	$(413,621)	$9,786

[1] Represents counterparty netting under agreements governing such derivatives.

Note 9 – Asset Retirement Obligations

Asset retirement obligations associated with retiring tangible long-lived assets are recognized as a liability in the period in which a legal obligation is incurred and becomes determinable and are included in “other noncurrent liabilities” on the condensed consolidated balance sheets. Accretion expense is included in “depreciation, depletion and amortization” on the condensed consolidated statements of operations. The fair value of additions to the asset retirement obligations is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors (2% for the nine months ended September 30, 2012); and (iv) a credit-adjusted risk-free interest rate (average of 6.9% for the nine months ended September 30, 2012). These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

The following presents a reconciliation of the asset retirement obligations (in thousands):

Asset retirement obligations at December 31, 2011	$71,142	
Liabilities added from acquisitions	63,896	
Liabilities added from drilling	1,053	
Current year accretion expense	5,781	
Settlements	(2,442	)
Revision of estimates	10,443	
Asset retirement obligations at September 30, 2012	$149,873	

Note 10 – Commitments and Contingencies

The Company has been named as a defendant in a number of lawsuits, including claims from royalty owners related to disputed royalty payments and royalty valuations. The Company has established reserves that management currently believes are adequate to provide for potential liabilities based upon its evaluation of these matters. For a certain statewide class action royalty payment dispute where a reserve has not yet been established, the Company has denied that it has any liability on the claims and has raised arguments and defenses that, if accepted by the court, will result in no loss to the Company. Discovery related to class certification has concluded. Briefing and the hearing on class certification have been deferred by court order pending the Tenth Circuit Court of Appeals' resolution of interlocutory appeals of two unrelated class certification orders. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any. In addition, the Company is involved in various other disputes arising in the ordinary course of business. The Company is not currently a party to any litigation or pending claims that it believes would have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

In 2008, Lehman Brothers Holdings Inc. and Lehman Brothers Commodity Services Inc. (together "Lehman"), filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York. In March 2011, the Company and Lehman entered into Termination Agreements under which the Company was granted general unsecured claims against Lehman in the amount of $51 million (the "Company Claim"). In December 2011, a Chapter 11 Plan ("Plan") was approved by the Bankruptcy Court. Based on the recovery estimates described in the approved disclosure statement relating to the Plan, the Company expects to ultimately receive a substantial portion of the Company Claim. On April 19, 2012, an initial distribution under the Plan of approximately $25 million was received by the Company resulting in a gain of approximately $18 million, which is included in "gains (losses) on oil and natural gas derivatives" on the condensed consolidated statement of operations. On October 1, 2012, the Company received an additional distribution under the Plan of approximately $3 million. In the aggregate, the Company has received approximately $28 million of the Company Claim and additional distributions may occur in the future.

Note 11 – Earnings Per Unit

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. The Company uses the treasury stock method to determine the dilutive effect.

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The following table provides a reconciliation of the numerators and denominators of the basic and diluted per unit computations for net income (loss):

	Net Income (Loss) (Numerator) (in thousands)	Units (Denominator)	Per Unit Amount
Three months ended September 30, 2012:			
Net loss:			
Allocated to units	$(430,005)		
Allocated to unvested restricted units	(1,398)		
	$(431,403)		
Net loss per unit:			
Basic net loss per unit		197,675	$(2.18)
Dilutive effect of unit equivalents		—	—
Diluted net loss per unit		197,675	$(2.18)
Three months ended September 30, 2011:			
Net income:			
Allocated to units	$837,627		
Allocated to unvested restricted units	(8,774)		
	$828,853		
Net income per unit:			
Basic net income per unit		174,956	$4.74
Dilutive effect of unit equivalents		688	(0.02)
Diluted net income per unit		175,644	$4.72
Nine months ended September 30, 2012:			
Net loss:			
Allocated to units	$(199,121)		
Allocated to unvested restricted units	(4,165)		
	$(203,286)		
Net loss per unit:			
Basic net loss per unit		196,152	$(1.04)
Dilutive effect of unit equivalents		—	—
Diluted net loss per unit		196,152	$(1.04)
Nine months ended September 30, 2011:			
Net income:			
Allocated to units	$628,054		
Allocated to unvested restricted units	(6,662)		
	$621,392		
Net income per unit:			
Basic net income per unit		171,076	$3.63
Dilutive effect of unit equivalents		749	(0.01)
Diluted net income per unit		171,825	$3.62

Basic units outstanding excludes the effect of weighted average anti-dilutive unit equivalents related to approximately 1 million unit options and warrants for the three months and nine months ended September 30, 2012. All equivalent units were anti-dilutive for the three months and nine months ended September 30, 2012. There were no anti-dilutive unit equivalents for the three months or nine months ended September 30, 2011.

Note 12 – Income Taxes

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with income tax liabilities and/or benefits of the Company passed through to unitholders. Limited liability companies are subject to Texas margin tax. Limited liability companies were also subject to state income taxes in the state of Michigan during the three months and nine months ended September 30, 2011. In addition, certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. As such, with the exception of the state of Texas and certain subsidiaries, the Company is not a taxable entity, it does not directly pay federal and state income taxes and recognition has not been given to federal and state income taxes for the operations of the Company. Amounts recognized for income taxes are reported in "income tax benefit (expense)" on the condensed consolidated statements of operations.

Note 13 – Supplemental Disclosures to the Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Cash Flows

"Other accrued liabilities" reported on the condensed consolidated balance sheets include the following:

	September 30, 2012	December 31, 2011
	(in thousands)	
Accrued compensation	$25,086	$19,581
Accrued interest	142,207	55,170
Other	2,101	1,147
	$169,394	$75,898

Supplemental disclosures to the condensed consolidated statements of cash flows are presented below:

	Nine Months Ended September 30, 2012	2011
	(in thousands)	
Cash payments for interest, net of amounts capitalized	$178,194	$163,345
Cash payments for income taxes	$306	$487
Noncash investing activities:		
In connection with the acquisition of oil and natural gas properties, liabilities were assumed as follows:		
Fair value of assets acquired	$2,854,410	$854,224
Cash paid, net of cash acquired	(2,487,767)	(846,976)
Receivables from sellers	772	2,662

Payables to sellers	(422)	(6,662)
Liabilities assumed	$366,993	$3,248

For purposes of the condensed consolidated statements of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. Restricted cash of approximately $4 million is included in “other noncurrent assets” on the condensed consolidated balance sheets at September 30, 2012, and December 31, 2011, and represents cash deposited by the Company into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

The Company manages its working capital and cash requirements to borrow only as needed from its Credit Facility. At September 30, 2012, and December 31, 2011, approximately $29 million and $54 million, respectively, were included in “accounts payable and accrued expenses” on the condensed consolidated balance sheets which represents reclassified net outstanding checks. The Company presents these net outstanding checks as cash flows from financing activities on the condensed consolidated statements of cash flows.

Note 14 – Related Party Transactions

One of the Company’s directors is the President and Chief Executive Officer of Superior Energy Services, Inc. (“Superior”), which provides oilfield services to the Company. For the three months and nine months ended September 30, 2012, the Company paid approximately $6 million and $14 million, respectively, to Superior and its subsidiaries for services rendered to the Company. These payments were consummated on terms equivalent to those that prevail in arm’s-length transactions.

Note 15 – Subsidiary Guarantors

The November 2019 Senior Notes, the May 2019 Senior Notes, the 2010 Issued Notes and the Original Senior Notes are guaranteed by all of the Company’s material subsidiaries. The Company is a holding company and has no independent assets or operations of its own, the guarantees under each series of notes are full and unconditional and joint and several, and any subsidiaries of the Company other than the subsidiary guarantors are minor. There are no restrictions on the Company’s ability to obtain cash dividends or other distributions of funds from the guarantor subsidiaries.

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

The following discussion contains forward-looking statements that reflect the Company's future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside the Company's control. The Company's actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, credit and capital market conditions, regulatory changes and other uncertainties, as well as those factors set forth in "Cautionary Statement" below and in Item 1A. "Risk Factors" in this Quarterly Report on Form 10-Q and in the Annual Report on Form 10-K for the year ended December 31, 2011, and elsewhere in the Annual Report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

The following discussion and analysis should be read in conjunction with the financial statements and related notes included in this Quarterly Report on Form 10-Q and in the Company's Annual Report on Form 10-K for the year ended December 31, 2011. A reference to a "Note" herein refers to the accompanying Notes to Condensed Consolidated Financial Statements contained in Item 1. "Financial Statements."

Executive Overview

LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN Energy is an independent oil and natural gas company that began operations in March 2003 and completed its IPO in January 2006. The Company's properties are located in eight operating regions in the United States ("U.S."):

- Mid-Continent, which includes properties in Oklahoma, Louisiana and the eastern portion of the Texas Panhandle (including the Granite Wash and Cleveland horizontal plays);
- Hugoton Basin, which includes properties located primarily in Kansas and the Shallow Texas Panhandle;
- Green River Basin, which includes properties located in southwest Wyoming;
- Permian Basin, which includes areas in west Texas and southeast New Mexico;
- Michigan/Illinois, which includes the Antrim Shale formation in the northern part of Michigan and oil properties in southern Illinois;
- Williston/Powder River Basin, which includes the Bakken formation in North Dakota and the Powder River Basin in Wyoming;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- East Texas, which includes properties located in east Texas.

Results for the three months ended September 30, 2012, included the following:

- oil, natural gas and NGL sales of approximately $444 million compared to $292 million for the third quarter of 2011;
- average daily production of 782 MMcfe/d compared to 379 MMcfe/d for the third quarter of 2011;
- realized gains on commodity derivatives of approximately $109 million compared to $92 million for the third quarter of 2011;
- adjusted EBITDA of approximately $402 million compared to $243 million for the third quarter of 2011;
- adjusted net income of approximately $90 million compared to $79 million for the third quarter of 2011;
- capital expenditures, excluding acquisitions, of approximately $258 million compared to $211 million for the third quarter of 2011; and
- 95 wells drilled (94 successful) compared to 78 wells drilled (all successful) for the third quarter of 2011.

Results for the nine months ended September 30, 2012, included the following:

- oil, natural gas and NGL sales of approximately $1,140 million compared to $836 million for the nine months ended September 30, 2011;
- average daily production of 628 MMcfe/d compared to 350 MMcfe/d for the nine months ended September 30, 2011;
- realized gains on commodity derivatives of approximately $282 million compared to $190 million for the nine months ended September 30, 2011;
- adjusted EBITDA of approximately $1.0 billion compared to $717 million for the nine months ended September 30, 2011;
- adjusted net income of approximately $199 million compared to $224 million for the nine months ended September 30, 2011;

- capital expenditures, excluding acquisitions, of approximately $815 million compared to $461 million for the nine months ended September 30, 2011; and
- 276 wells drilled (272 successful) compared to 179 wells drilled (177 successful) for the nine months ended September 30, 2011.

Adjusted EBITDA and adjusted net income are non-GAAP financial measures used by management to analyze Company performance. Adjusted EBITDA is a measure used by Company management to evaluate cash flow and the Company’s ability to sustain or increase distributions. The most significant reconciling items between net income (loss) and adjusted EBITDA are interest expense and noncash items, including the change in fair value of derivatives, and depreciation, depletion and amortization. Adjusted net income is used by Company management to evaluate its operational performance from oil and natural gas properties, prior to unrealized (gains) losses on derivatives, realized (gains) losses on canceled derivatives, realized gain on recovery of bankruptcy claim, impairment of long-lived assets, loss on extinguishment of debt and (gains) losses on sale of assets, net. See “Non-GAAP Financial Measures” on page 39 for a reconciliation of each non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Acquisitions

On July 31, 2012, the Company completed the acquisition of certain oil and natural gas properties in the Jonah Field located in the Green River Basin of southwest Wyoming from BP America Production Company (“BP”) for total consideration of approximately $990 million. The acquisition included approximately 806 Bcfe of proved reserves as of the acquisition date.

On May 1, 2012, the Company completed the acquisition of certain oil and natural gas properties located in east Texas for total consideration of approximately $168 million. The acquisition included approximately 110 Bcfe of proved reserves as of the acquisition date.

On April 3, 2012, the Company entered into a joint-venture agreement (“Agreement”) with an affiliate of Anadarko Petroleum Corporation (“Anadarko”) whereby the Company participates as a partner in the CO2 enhanced oil recovery development of the Salt Creek Field, located in the Powder River Basin of Wyoming. Anadarko assigned the Company 23% of its interest in the field in exchange for future funding of $400 million of Anadarko’s development costs. As of September 30, 2012, the Company has paid approximately $119 million towards the future funding commitment. The acquisition included approximately 16 MMBoe (96 Bcfe) of proved reserves as of the Agreement date.

On March 30, 2012, the Company completed the acquisition of certain oil and natural gas properties located in the Hugoton Basin in Kansas from BP for total consideration of approximately $1.16 billion. The acquisition included approximately 701 Bcfe of proved reserves as of the acquisition date.
During the nine months ended September 30, 2012, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $52 million in total consideration for these properties.

Proved reserves as of the acquisition date for all of the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month.

Financing and Liquidity

In January 2012, the Company, under its equity distribution agreement, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $2 million in commissions and professional services expenses). The Company used the net proceeds for general corporate purposes, including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At September 30, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

In January 2012, the Company completed a public offering of units for net proceeds of approximately $674 million. The Company used the net proceeds from the sale of these units to repay a portion of the outstanding indebtedness under its Credit Facility.

In March 2012, the Company issued $1.8 billion in aggregate principal amount of 6.25% senior notes due November 2019 (see Note 6) and used the net proceeds of approximately $1.77 billion to fund the Hugoton acquisition (see Note 2). The remaining proceeds were used to repay indebtedness under the Company's Credit Facility and for general corporate purposes.

The Company's Fifth Amended and Restated Credit Agreement ("Credit Facility") provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) maximum commitment amount. In May 2012, the Company entered into an amendment to its Credit Facility to increase the borrowing base to $3.5 billion and extend the maturity date from April 2016 to April 2017. In July 2012, the Company entered into an amendment to its Credit Facility to increase the maximum commitment amount from $2.0 billion to $3.0 billion.

On May 8, 2012, the Company filed a registration statement on Form S-4 to register exchange notes that are identical in all material respects to those of the outstanding May 2019 Senior Notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the outstanding notes do not apply to the exchange notes. On September 24, 2012, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $750 million outstanding principal amount of May 2019 Senior Notes for an equal amount of new May 2019 Senior Notes. The offer expired on October 23, 2012.

On October 17, 2012, LinnCo, LLC ("LinnCo"), a wholly owned subsidiary of LINN Energy at September 30, 2012, completed its initial public offering (the "LinnCo IPO") of 34,787,500 of its common shares representing limited liability company interests for net proceeds of approximately $1.2 billion. The net proceeds LinnCo received from the offering were used to acquire 34,787,500 LINN Energy units which are equal to the number of LinnCo shares sold in the offering. The Company used the proceeds from the sale of the units to LinnCo to pay the expenses of the offering and repay a portion of the outstanding indebtedness under its Credit Facility.

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

Results of Operations

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

	Three Months Ended September 30,		
	2012	2011	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$101,984	$66,667	$35,317
Oil sales	247,354	178,559	68,795
NGL sales	94,744	47,256	47,488
Total oil, natural gas and NGL sales	444,082	292,482	151,600
Gains (losses) on oil and natural gas derivatives [1]	(411,405)	824,240	(1,235,645)
Marketing and other revenues	15,651	2,761	12,890
	48,328	1,119,483	(1,071,155)
Expenses:			
Lease operating expenses	91,990	62,907	29,083
Transportation expenses	18,274	7,821	10,453
Marketing expenses	14,923	850	14,073
General and administrative expenses [2]	45,166	29,891	15,275
Exploration costs	390	503	(113)
Depreciation, depletion and amortization	167,695	88,328	79,367
Taxes, other than income taxes	37,885	20,875	17,010
(Gains) losses on sale of assets and other, net	16	358	(342)
	376,339	211,533	164,806
Other income and (expenses)	(106,944)	(67,461)	(39,483)
Income (loss) before income taxes	(434,955)	840,489	(1,275,444)
Income tax benefit (expense)	4,950	(2,862)	7,812
Net income (loss)	$(430,005)	$837,627	$(1,267,632)
Adjusted EBITDA [3]	$402,446	$243,266	$159,180
Adjusted net income [3]	$89,847	$78,554	$11,293

(1) In September 2011, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in realized gains of approximately $27 million.

(2) General and administrative expenses for the three months ended September 30, 2012, and September 30, 2011, include approximately $7 million and $5 million, respectively, of noncash unit-based compensation expenses.

(3) This is a non-GAAP measure used by management to analyze the Company's performance. See "Non-GAAP Financial Measures" on page 39 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

	Three Months Ended September 30,			
	2012	2011	Variance	
Average daily production:				
Natural gas (MMcf/d)	409	170	141	%
Oil (MBbls/d)	30.8	22.6	36	%
NGL (MBbls/d)	31.4	12.2	157	%
Total (MMcfe/d)	782	379	106	%
Weighted average prices (hedged): (1)				
Natural gas (Mcf)	$5.17	$8.05	(36	)%
Oil (Bbl)	$92.98	$88.62	5	%
NGL (Bbl)	$32.83	$42.01	(22	)%
Weighted average prices (unhedged): (2)				
Natural gas (Mcf)	$2.71	$4.26	(36	)%
Oil (Bbl)	$87.22	$85.89	2	%
NGL (Bbl)	$32.83	$42.01	(22	)%
Average NYMEX prices:				
Natural gas (MMBtu)	$2.80	$4.19	(33	)%
Oil (Bbl)	$92.22	$89.76	3	%
Costs per Mcfe of production:				
Lease operating expenses	$1.28	$1.80	(29	)%
Transportation expenses	$0.25	$0.22	14	%
General and administrative expenses (3)	$0.63	$0.86	(27	)%
Depreciation, depletion and amortization	$2.33	$2.53	(8	)%
Taxes, other than income taxes	$0.53	$0.60	(12	)%

(1) Includes the effect of realized gains on derivatives of approximately $109 million and $65 million (excluding $27 million realized gains on canceled contracts) for the three months ended September 30, 2012, and September 30, 2011, respectively.

(2) Does not include the effect of realized gains (losses) on derivatives.

(3) General and administrative expenses for the three months ended September 30, 2012, and September 30, 2011, include approximately $7 million and $5 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the three months ended September 30, 2012, and September 30, 2011, were $0.54 per Mcfe and $0.70 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company’s performance.

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

Revenues and Other

Oil, Natural Gas and NGL Sales
Oil, natural gas and NGL sales increased approximately $152 million or 52% to approximately $444 million for the three months ended September 30, 2012, from approximately $292 million for the three months ended September 30, 2011, due to higher production volumes and higher oil prices partially offset by lower natural gas and NGL prices. Higher oil prices resulted in an increase in revenues of approximately $4 million. Lower natural gas and NGL prices resulted in a decrease in revenues of approximately $58 million and $26 million, respectively.

Average daily production volumes increased to 782 MMcfe/d during the three months ended September 30, 2012, from 379 MMcfe/d during the three months ended September 30, 2011. Higher natural gas, NGL and oil production volumes resulted in an increase in revenues of approximately $93 million, $74 million and $65 million, respectively.

The following sets forth average daily production by region:

	Three Months Ended September 30,						
	2012	2011	Variance				
Average daily production (MMcfe/d):							
Mid-Continent	351	198	153		78	%
Hugoton Basin	150	40	110		276	%
Green River Basin	98	—	98		—	
Permian Basin	82	75	7		9	%
Michigan/Illinois	35	36	(1	)	(2	)%
Williston/Powder River Basin	28	15	13		76	%
East Texas	25	—	25		—	
California	13	15	(2	)	(12	)%
	782	379	403		106	%

The 78% increase in average daily production volumes in the Mid-Continent region primarily reflects the Company's 2011 and 2012 capital drilling programs in the Granite Wash formation, as well as the impact of the acquisition from Plains in December 2011. The increase in average daily production volumes in the Hugoton Basin region primarily reflects the impact of the acquisition from BP in March 2012. Average daily production volumes in the Green River Basin region reflect the impact of the acquisition from BP in July 2012. Average daily production volumes in the Permian Basin region reflect the impact of acquisitions in 2011 and subsequent development capital spending. The Michigan/Illinois and California regions consist of low-decline asset bases and continue to produce at consistent levels. The increase in average daily production volumes in the Williston/Powder River Basin region reflects the impact of the joint-venture agreement entered into with Anadarko in April 2012. Average daily production volumes in the East Texas region reflect the impact of the acquisition in May 2012 (see Note 2).

Gains (Losses) on Oil and Natural Gas Derivatives
The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Item 3. "Quantitative and Qualitative Disclosures About Market Risk," Note 7 and Note 8 for additional information about the Company's commodity derivatives. During the three months ended September 30, 2012, the Company had commodity derivative contracts for approximately 107% of its natural gas production and 104% of its oil production, which resulted in realized gains of approximately $109 million. During the three months ended September 30, 2011, the Company had commodity derivative contracts for approximately 103% of its natural gas production and 102% of its oil production and recognized realized gains of approximately $92 million (including realized gains on canceled contracts of approximately $27 million). Unrealized

gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, unrealized losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, unrealized gains are recognized. During the third quarter of 2012, expected future oil and natural gas prices increased, which resulted in net unrealized losses of approximately $520 million for the three months ended September 30, 2012. During the third quarter of 2011, expected future oil and natural gas prices decreased, which resulted in net unrealized gains on derivatives of approximately $732 million for the three months ended September 30, 2011. For information about the Company’s credit risk related to derivative contracts, see “Counterparty Credit Risk” in “Liquidity and Capital Resources” below.

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Marketing and Other Revenues
Marketing revenues represent third-party activities associated with company-owned gathering systems and plants. Marketing and other revenues increased by approximately $13 million or 467% to approximately $16 million for the three months ended September 30, 2012, from approximately $3 million for the three months ended September 30, 2011, primarily due to the acquisition of the Jayhawk natural gas processing plant from BP in March 2012.

Expenses

Lease Operating Expenses
Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by approximately $29 million or 46% to approximately $92 million for the three months ended September 30, 2012, from approximately $63 million for the three months ended September 30, 2011. Lease operating expenses increased primarily due to costs associated with properties acquired during 2011 and 2012 (see Note 2). Lease operating expenses per Mcfe decreased to $1.28 per Mcfe for the three months ended September 30, 2012, from $1.80 per Mcfe for the three months ended September 30, 2011, primarily due to lower rates on newly acquired properties.

Transportation Expenses
Transportation expenses increased by approximately $10 million or 134% to approximately $18 million for the three months ended September 30, 2012, from approximately $8 million for the three months ended September 30, 2011, primarily due to acquisitions in late 2011 and early 2012.

Marketing Expenses
Marketing expenses represent third-party activities associated with company-owned gathering systems and plants. Marketing expenses increased by approximately $14 million or 1,656% to approximately $15 million for the three months ended September 30, 2012, from approximately $1 million for the three months ended September 30, 2011, primarily due to the acquisition of the Jayhawk natural gas processing plant from BP in March 2012.

General and Administrative Expenses
General and administrative expenses are costs not directly associated with field operations and reflect the costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased by approximately $15 million or 51% to approximately $45 million for the three months ended September 30, 2012, from approximately $30 million for the three months ended September 30, 2011. The increase was primarily due to an increase in salaries and benefits related expenses of approximately $9 million, driven primarily by increased employee headcount, and an increase in acquisition related expenses of approximately $6 million. General and administrative expenses per Mcfe decreased to $0.63 per Mcfe for the three months ended September 30, 2012, from $0.86 per Mcfe for the three months ended September 30, 2011, due to higher production volumes.

Depreciation, Depletion and Amortization
Depreciation, depletion and amortization increased by approximately $80 million or 90% to approximately $168 million for the three months ended September 30, 2012, from approximately $88 million for the three months ended September 30, 2011. Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per Mcfe decreased to $2.33 per Mcfe for the three months ended September 30, 2012, from $2.53 per Mcfe for the three months ended September 30, 2011, primarily due to higher production volumes associated with newly acquired properties with lower depletion rates.

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $17 million or 82% to approximately $38 million for the three months ended September 30, 2012, from approximately $21 million for the three months ended September 30, 2011. Severance taxes, which are a function of revenues generated from production, increased approximately $6 million compared to the three months ended September 30, 2011, primarily due to higher production volumes partially offset by lower natural gas and NGL prices. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased by approximately $11 million compared to the three months ended September 30, 2011, primarily due to property acquisitions in 2011 and 2012 and higher rates on the Company’s base properties.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

Other Income and (Expenses)

	Three Months Ended September 30, 2012	2011	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$(105,697)	$(65,848)	$(39,849)
Other, net	(1,247)	(1,613)	366
	$(106,944)	$(67,461)	$(39,483)

Other income and (expenses) increased by approximately $39 million for the three months ended September 30, 2012, compared to the three months ended September 30, 2011. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees and expenses associated with the November 2019 Senior Notes, as defined in Note 6, and amendments made to the Company’s Credit Facility during 2012. See “Debt” in “Liquidity and Capital Resources” below for additional details.

Income Tax Benefit (Expense)

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with income tax liabilities and/or benefits of the Company passed through to unitholders. Limited liability companies are subject to Texas margin tax. Limited liability companies were also subject to state income taxes in the state of Michigan during the three months ended September 30, 2011. In addition, certain of the Company’s subsidiaries are Subchapter C-corporations subject to federal and state income taxes. The Company recognized income tax benefit of approximately $5 million for the three months ended September 30, 2012, compared to income tax expense of approximately $3 million for the three months ended September 30, 2011. Income tax expense decreased primarily due to lower income from the Company’s taxable subsidiaries during the three months ended September 30, 2012, compared to the same period in 2011.

Net Income (Loss)

Net income decreased by approximately $1.3 billion or 151% to a net loss of approximately $430 million for the three months ended September 30, 2012, from net income of approximately $838 million for the three months ended September 30, 2011. The decrease was primarily due to lower gains on oil and natural gas derivatives and higher expenses, including interest, partially offset by higher production revenues. See discussions above for explanations of variances.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $159 million or 65% to approximately $402 million for the three months ended September 30, 2012, from approximately $243 million for the three months ended September 30, 2011. The increase was primarily due to higher revenues excluding unrealized gains (losses) on oil and natural gas derivatives, partially offset by higher expenses. See discussions above for explanations of variances. See “Non-GAAP Financial Measures” on page 39 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Adjusted Net Income

Adjusted net income (a non-GAAP financial measure) increased by approximately $11 million or 14% to approximately $90 million for the three months ended September 30, 2012, from approximately $79 million for the three months ended September 30, 2011. The increase was primarily due to higher revenues excluding unrealized gains (losses) on oil and natural gas derivatives, partially offset by higher expenses, including interest. See discussions above for explanations of variances.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

Results of Operations

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

	Nine Months Ended September 30,		
	2012	2011	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$227,027	$204,265	$22,762
Oil sales	702,863	508,651	194,212
NGL sales	210,314	122,663	87,651
Total oil, natural gas and NGL sales	1,140,204	835,579	304,625
Gains on oil and natural gas derivatives (1)	30,273	660,279	(630,006)
Marketing and other revenues	32,538	7,723	24,815
	1,203,015	1,503,581	(300,566)
Expenses:			
Lease operating expenses	233,755	165,171	68,584
Transportation expenses	50,651	20,152	30,499
Marketing expenses	22,073	2,703	19,370
General and administrative expenses (2)	129,672	91,994	37,678
Exploration costs	1,207	1,498	(291)
Depreciation, depletion and amortization	428,477	234,039	194,438
Impairment of long-lived assets	146,499	—	146,499
Taxes, other than income taxes	93,736	56,920	36,816
Losses on sale of assets and other, net	1,508	1,944	(436)
	1,107,578	574,421	533,157
Other income and (expenses)	(290,078)	(292,376)	2,298
Income (loss) before income taxes	(194,641)	636,784	(831,425)
Income tax expense	(4,480)	(8,730)	4,250
Net income (loss)	$(199,121)	$628,054	$(827,175)
Adjusted EBITDA (3)	$1,023,720	$716,868	$306,852
Adjusted net income (3)	$199,468	$224,218	$(24,750)

(1) In September 2011, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in realized gains of approximately $27 million.

(2) General and administrative expenses for the nine months ended September 30, 2012, and September 30, 2011, include approximately $20 million and $16 million, respectively, of noncash unit-based compensation expenses.

(3) This is a non-GAAP measure used by management to analyze the Company’s performance. See “Non-GAAP Financial Measures” on page 39 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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

	Nine Months Ended September 30, 2012	2011	Variance	
Average daily production:				
Natural gas (MMcf/d)	318	166	92	%
Oil (MBbls/d)	28.4	20.4	39	%
NGL (MBbls/d)	23.2	10.3	125	%
Total (MMcfe/d)	628	350	79	%
Weighted average prices (hedged): (1)				
Natural gas (Mcf)	$5.60	$8.46	(34	)%
Oil (Bbl)	$92.91	$88.45	5	%
NGL (Bbl)	$33.04	$43.62	(24	)%
Weighted average prices (unhedged): (2)				
Natural gas (Mcf)	$2.60	$4.52	(42	)%
Oil (Bbl)	$90.33	$91.19	(1	)%
NGL (Bbl)	$33.04	$43.62	(24	)%
Average NYMEX prices:				
Natural gas (MMBtu)	$2.59	$4.21	(38	)%
Oil (Bbl)	$96.21	$95.48	1	%
Costs per Mcfe of production:				
Lease operating expenses	$1.36	$1.73	(21	)%
Transportation expenses	$0.29	$0.21	38	%
General and administrative expenses (3)	$0.75	$0.96	(22	)%
Depreciation, depletion and amortization	$2.49	$2.45	2	%
Taxes, other than income taxes	$0.54	$0.60	(10	)%

(1) Includes the effect of realized gains on derivatives of approximately $282 million (excluding approximately $18 million realized gain on recovery of bankruptcy claim) and $163 million (excluding $27 million realized gains on canceled contracts) for the nine months ended September 30, 2012, and September 30, 2011, respectively.

(2) Does not include the effect of realized gains (losses) on derivatives.

(3) General and administrative expenses for the nine months ended September 30, 2012, and September 30, 2011, include approximately $20 million and $16 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the nine months ended September 30, 2012, and September 30, 2011, were $0.63 per Mcfe and $0.80 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

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Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales increased approximately $304 million or 36% to approximately $1.1 billion for the nine months ended September 30, 2012, from approximately $836 million for the nine months ended September 30, 2011, due to higher production volumes partially offset by lower natural gas, NGL and oil prices. Lower natural gas, NGL and oil prices resulted in a decrease in revenues of approximately $167 million, $67 million and $7 million, respectively.

Average daily production volumes increased to 628 MMcfe/d during the nine months ended September 30, 2012, from 350 MMcfe/d during the nine months ended September 30, 2011. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $200 million, $190 million and $155 million, respectively.

The following sets forth average daily production by region:

	Nine Months Ended September 30,			
	2012	2011	Variance	
Average daily production (MMcfe/d):				
Mid-Continent	309	182	127	70 %
Hugoton Basin	114	39	75	193 %
Green River Basin	33	—	33	—
Permian Basin	84	70	14	20 %
Michigan/Illinois	35	36	(1)	(1)%
Williston/Powder River Basin	26	9	17	176 %
East Texas	14	—	14	—
California	13	14	(1)	(7)%
	628	350	278	80 %

The 70% increase in average daily production volumes in the Mid-Continent region primarily reflects the Company’s 2011 and 2012 capital drilling programs in the Granite Wash formation, as well as the impact of the acquisition in the Cleveland horizontal play in June 2011 and the acquisition from Plains in December 2011. The increase in average daily production volumes in the Hugoton Basin region primarily reflects the impact of the acquisition from BP in March 2012. Average daily production volumes in the Green River Basin region reflect the impact of the acquisition from BP in July 2012. Average daily production volumes in the Permian Basin region reflect the impact of acquisitions in 2011 and subsequent development capital spending. The Michigan/Illinois and California regions consist of low-decline asset bases and continue to produce at consistent levels. The increase in average daily production volumes in the Williston/Powder River Basin region reflect the impact of acquisitions in 2011 and the joint-venture agreement entered into with Anadarko in April 2012. Average daily production volumes in the East Texas region reflect the impact of the acquisition in May 2012 (see Note 2).

Gains (Losses) on Oil and Natural Gas Derivatives

The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Item 3. “Quantitative and Qualitative Disclosures About Market Risk,” Note 7 and Note 8 for additional information about the Company’s commodity derivatives. During the nine months ended September 30, 2012, the Company had commodity derivative contracts for approximately 113% of its natural gas production and 106% of its oil production, which resulted in realized gains of approximately $282 million. The results for 2012 also include a realized gain related to the recovery of a bankruptcy claim of approximately $18 million (see Note 10). During the nine months ended September 30, 2011, the Company had commodity derivative contracts for approximately 107% of its natural gas production and 104% of its oil production and recognized realized gains of approximately $190 million (including realized gains on canceled contracts of approximately $27 million). Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, unrealized losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, unrealized gains are recognized. During the first three quarters of 2012, expected future oil prices decreased resulting in unrealized gains of approximately $82 million, and natural gas prices increased resulting in unrealized losses of approximately $352 million, for net unrealized losses on derivatives of approximately $270 million for the nine months ended September 30, 2012. During the first three quarters of 2011, expected future oil and natural gas prices decreased, which resulted in net unrealized gains on derivatives of approximately $471 million for the nine months ended September 30, 2011. For information about the

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Company's credit risk related to derivative contracts, see "Counterparty Credit Risk" in "Liquidity and Capital Resources" below.

Marketing and Other Revenues

Marketing revenues represent third-party activities associated with company-owned gathering systems and plants. Marketing and other revenues increased by approximately $25 million or 321% to approximately $33 million for the nine months ended September 30, 2012, from approximately $8 million for the nine months ended September 30, 2011, primarily due to the acquisition of the Jayhawk natural gas processing plant from BP in March 2012.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by approximately $69 million or 42% to approximately $234 million for the nine months ended September 30, 2012, from approximately $165 million for the nine months ended September 30, 2011. Lease operating expenses increased primarily due to costs associated with properties acquired during 2011 and 2012 (see Note 2). Lease operating expenses per Mcfe decreased to $1.36 per Mcfe for the nine months ended September 30, 2012, from $1.73 per Mcfe for the nine months ended September 30, 2011, primarily due to lower rates on newly acquired properties.

Transportation Expenses

Transportation expenses increased by approximately $31 million or 151% to approximately $51 million for the nine months ended September 30, 2012, from approximately $20 million for the nine months ended September 30, 2011, primarily due to acquisitions in late 2011 and early 2012.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems and plants. Marketing expenses increased by approximately $19 million or 717% to approximately $22 million for the nine months ended September 30, 2012, from approximately $3 million for the nine months ended September 30, 2011, primarily due to the acquisition of the Jayhawk natural gas processing plant from BP in March 2012.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations and reflect the costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased by approximately $38 million or 41% to approximately $130 million for the nine months ended September 30, 2012, from approximately $92 million for the nine months ended September 30, 2011. The increase was primarily due to an increase in salaries and benefits related expenses of approximately $18 million, driven primarily by increased employee headcount, and an increase in acquisition related expenses of approximately $17 million. General and administrative expenses per Mcfe decreased to $0.75 per Mcfe for the nine months ended September 30, 2012, from $0.96 per Mcfe for the nine months ended September 30, 2011, due to higher production volumes.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $194 million or 83% to approximately $428 million for the nine months ended September 30, 2012, from approximately $234 million for the nine months ended September 30, 2011. Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per Mcfe also increased to $2.49 per Mcfe for the nine months ended September 30, 2012, from $2.45 per Mcfe for the nine months ended September 30, 2011, primarily due to higher production volumes in operating areas with higher depletion rates.

Impairment of Long-Lived Assets

During the nine months ended September 30, 2012, the Company recorded a noncash impairment charge, before and after tax, of approximately $146 million associated with proved oil and natural gas properties related to a decline in commodity prices. The Company recorded no impairment charge for the nine months ended September 30, 2011.

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $37 million or 65% to approximately $94 million for the nine months ended September 30, 2012, from approximately $57 million for the nine months ended September 30, 2011. Severance taxes, which are a function of revenues generated from production, increased approximately $14 million compared to the nine months ended September 30, 2011, primarily due to higher production volumes partially offset by lower commodity prices. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased by approximately $22 million compared to the nine months ended

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September 30, 2011, primarily due to property acquisitions in 2011 and 2012 and higher rates on the Company’s base properties.

Other Income and (Expenses)

	Nine Months Ended September 30,		
	2012	2011	Variance
	(in thousands)		
Loss on extinguishment of debt	$—	$(94,372)	$94,372
Interest expense, net of amounts capitalized	(277,606)	(191,673)	(85,933)
Other, net	(12,472)	(6,331)	(6,141)
	$(290,078)	$(292,376)	$2,298

Other income and (expenses) decreased by approximately $2 million for the nine months ended September 30, 2012, compared to the nine months ended September 30, 2011. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees and expenses associated with the May 2019 Senior Notes and the November 2019 Senior Notes, as defined in Note 6, and amendments made to the Company’s Credit Facility during 2012. For the nine months ended September 30, 2011, the Company recorded a loss on extinguishment of debt of approximately $94 million as a result of the redemptions of and cash tender offers for a portion of the Original Senior Notes, as defined in Note 6. See “Debt” in “Liquidity and Capital Resources” below for additional details.

Income Tax Expense

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with income tax liabilities and/or benefits of the Company passed through to unitholders. Limited liability companies are subject to Texas margin tax. Limited liability companies were also subject to state income taxes in the state of Michigan during the nine months ended September 30, 2011. In addition, certain of the Company’s subsidiaries are Subchapter C-corporations subject to federal and state income taxes. The Company recognized income tax expense of approximately $4 million for the nine months ended September 30, 2012, compared to approximately $9 million for the nine months ended September 30, 2011. Income tax expense decreased primarily due to lower income from the Company’s taxable subsidiaries during the nine months ended September 30, 2012, compared to the same period in 2011.

Net Income (Loss)

Net income decreased by approximately $827 million or 132% to a net loss of approximately $199 million for the nine months ended September 30, 2012, from net income of approximately $628 million for the nine months ended September 30, 2011. The decrease was primarily due to lower gains on oil and natural gas derivatives and higher expenses, including interest, partially offset by higher production revenues. See discussions above for explanations of variances.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $307 million or 43% to approximately $1.0 billion for the nine months ended September 30, 2012, from approximately $717 million for the nine months ended September 30, 2011. The increase was primarily due to higher revenues excluding unrealized gains (losses) on oil and natural gas derivatives, partially offset by higher expenses. See discussions above for explanations of variances. See “Non-GAAP Financial Measures” on page 39 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Adjusted Net Income

Adjusted net income (a non-GAAP financial measure) decreased by approximately $25 million or 11% to approximately $199 million for the nine months ended September 30, 2012, from approximately $224 million for the nine months ended September 30, 2011. The decrease was primarily due to higher expenses, including interest, partially offset by higher revenues excluding unrealized gains (losses) on oil and natural gas derivatives. See discussions above for explanations of variances.

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

Liquidity and Capital Resources

The Company utilizes funds from equity and debt offerings, bank borrowings and cash flow from operations for capital resources and liquidity. To date, the primary use of capital has been for acquisitions and the development of oil and natural gas properties. For the nine months ended September 30, 2012, the Company's capital expenditures, excluding acquisitions, were approximately $815 million. For 2012, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $1.1 billion, including approximately $1.05 billion related to the Company's oil and natural gas capital program. This estimate reflects amounts for the development of properties associated with acquisitions (see Note 2), is under continuous review and subject to ongoing adjustment. The Company expects to fund these capital expenditures primarily with cash flow from operations and bank borrowings.

As the Company pursues growth, it continually monitors the capital resources available to meet future financial obligations and planned capital expenditures. The Company's future success in growing reserves and production volumes will be highly dependent on the capital resources available and its success in drilling for or acquiring additional reserves. The Company actively reviews acquisition opportunities on an ongoing basis. If the Company were to make significant additional acquisitions for cash, it would need to borrow additional amounts under its Credit Facility, if available, or obtain additional debt or equity financing. The Company's Credit Facility and Indentures governing its November 2019 Senior Notes, May 2019 Senior Notes, 2010 Issued Senior Notes and Original Senior Notes impose certain restrictions on the Company's ability to obtain additional debt financing. Based upon current expectations, the Company believes liquidity and capital resources will be sufficient to conduct its business and operations.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Nine Months Ended September 30, 2012	2011	Variance
	(in thousands)		
Net cash:			
Provided by operating activities [1]	$144,431	$486,429	$(341,998)
Used in investing activities	(3,234,779)	(1,257,274)	(1,977,505)
Provided by financing activities	3,090,388	544,919	2,545,469
Net increase (decrease) in cash and cash equivalents	$40	$(225,926)	$225,966

(1) The nine months ended September 30, 2012, and September 30, 2011, include premiums paid for commodity derivatives of approximately $583 million and $60 million, respectively.

Operating Activities

Cash provided by operating activities for the nine months ended September 30, 2012, was approximately $144 million, compared to approximately $486 million for the nine months ended September 30, 2011. The decrease was primarily due to approximately $583 million in premiums paid for commodity derivatives during the nine months ended September 30, 2012, compared to $60 million in premiums paid during the same period in 2011. Higher premiums and higher expenses were partially offset by increased revenues primarily due to higher production volumes.

Premiums paid during the nine months ended September 30, 2012, and September 30, 2011, were for commodity derivative contracts that hedge future production. These derivative contracts provide the Company long-term cash flow predictability to manage its business, service debt and pay distributions and are primarily funded through the Company's Credit Facility. The amount of derivative contracts the Company enters into in the future will be directly related to expected future production. See Note 7 and Note 8 for additional details about the Company's commodity derivatives.

Investing Activities
The following provides a comparative summary of cash flow from investing activities:

	Nine Months Ended September 30,	
	2012	2011
	(in thousands)	
Cash flow from investing activities:		
Acquisition of oil and natural gas properties	$(2,487,767)	$(846,976)
Capital expenditures	(748,450)	(421,074)
Proceeds from sale of properties and equipment and other	1,438	10,776
	$(3,234,779)	$(1,257,274)

The primary use of cash in investing activities is for capital spending, including acquisitions and the development of the Company's oil and natural gas properties. Cash used in investing activities for the nine months ended September 30, 2012, primarily relates to the acquisitions of properties in the Hugoton Basin, Williston/Powder River Basin, East Texas and Green River Basin regions. See Note 2 for additional details of acquisitions. Development expenditures are higher primarily due to increased drilling activities in the Granite Wash formation.

Financing Activities
Cash provided by financing activities for the nine months ended September 30, 2012, was approximately $3.1 billion, compared to approximately $545 million for the nine months ended September 30, 2011. The increase in financing cash flow needs was primarily attributable to increased acquisitions and development activity during the nine months ended September 30, 2012. The following provides a comparative summary of proceeds from borrowings and repayments of debt:

	Nine Months Ended September 30,	
	2012	2011
	(in thousands)	
Proceeds from borrowings:		
Credit facility	$3,130,000	$770,000
Senior notes	1,799,802	744,240
	$4,929,802	$1,514,240
Repayments of debt:		
Credit facility	$(2,085,000)	$(705,000)
Senior notes	—	(449,679)
	$(2,085,000)	$(1,154,679)

Debt

The Company's Fifth Amended and Restated Credit Agreement ("Credit Facility") provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount. In October 2011, as part of the semi-annual redetermination, a borrowing base of $3.0 billion was approved by the lenders with a maximum commitment amount of $1.5 billion. In February 2012, lenders approved an increase in the maximum commitment amount to $2.0 billion. In May 2012, the Company entered into an amendment to its Credit Facility to increase the borrowing base to $3.5 billion and extend the maturity date from April 2016 to April 2017. In July 2012, the Company entered into an amendment to its Credit Facility to increase the maximum commitment amount from $2.0 billion to $3.0 billion. At September 30, 2012, available borrowing capacity was approximately $1.0 billion, which includes a $5 million reduction in availability for outstanding letters of credit.

On March 2, 2012, the Company issued $1.8 billion in aggregate principal amount of 6.25% senior notes due November 2019 (see Note 6) and used the net proceeds of approximately $1.77 billion to fund the Hugoton acquisition (see Note 2). The remaining proceeds were used to repay indebtedness under the Company’s Credit Facility and for general corporate purposes.

On May 8, 2012, the Company filed a registration statement on Form S-4 to register exchange notes that are identical in all material respects to those of the outstanding May 2019 Senior Notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the outstanding notes do not apply to the exchange notes. On September 24, 2012, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $750 million outstanding principal amount of May 2019 Senior Notes for an equal amount of new May 2019 Senior Notes. The offer expired on October 23, 2012.

The Company depends, in part, on its Credit Facility for future capital needs. In addition, the Company has drawn on the Credit Facility to fund or partially fund quarterly cash distribution payments, since it uses operating cash flow primarily for investing activities and borrows as cash is needed. Absent such borrowings, the Company would have at times experienced a shortfall in cash available to pay the declared quarterly cash distribution amount. If an event of default occurs and is continuing under the Credit Facility, the Company would be unable to make borrowings to fund distributions. For additional information about this matter and other risk factors that could affect the Company, see Item 1A. "Risk Factors."

Counterparty Credit Risk

The Company accounts for its commodity derivatives at fair value. The Company's counterparties are current participants or affiliates of participants in its Credit Facility or were participants or affiliates of participants in its Credit Facility at the time it originally entered into the derivatives. The Credit Facility is secured by the Company's oil, natural gas and NGL reserves; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

Equity Distribution Agreement

In August 2011, the Company entered into an equity distribution agreement, pursuant to which it may from time to time issue and sell units representing limited liability company interests having an aggregate offering price of up to $500 million. Sales of units, if any, will be made through a sales agent by means of ordinary brokers' transactions, in block transactions, or as otherwise agreed with the agent. The Company expects to use the net proceeds from any sale of the units for general corporate purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

In January 2012, the Company, under its equity distribution agreement, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $2 million in commissions and professional service expenses). The Company used the net proceeds for general corporate purposes, including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At September 30, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

Public Offering of Units

In January 2012, the Company sold 19,550,000 units representing limited liability company interests at $35.95 per unit ($34.512 per unit, net of underwriting discount) for net proceeds of approximately $674 million (after underwriting discount and offering expenses of approximately $28 million). The Company used the net proceeds from the sale of these units to repay a portion of the outstanding indebtedness under its Credit Facility.

LinnCo Initial Public Offering

On October 17, 2012, LinnCo, a wholly owned subsidiary of LINN Energy at September 30, 2012, completed the LinnCo IPO of 34,787,500 of its common shares representing limited liability company interests at a price to the public of $36.50 per share ($34.858 per share, net of underwriting discount and structuring fee) for net proceeds of approximately $1.2 billion (after underwriting discount and structuring fee of approximately $57 million). The net proceeds LinnCo received from the offering were used to acquire 34,787,500 LINN Energy units which are equal to the number of LinnCo shares sold in the offering. The Company used the proceeds from the sale of the units to LinnCo to pay the expenses of the offering and repay a portion of the outstanding indebtedness under its Credit Facility.

Distributions

Under the Company’s limited liability company agreement, the Company’s unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. The following provides a summary of distributions paid by the Company during the nine months ended September 30, 2012:

Date Paid	Period Covered by Distribution	Distribution Per Unit	Total Distribution (in millions)
August 2012	April 1 – June 30, 2012	$0.725	$145
May 2012	January 1 – March 31, 2012	$0.725	$144
February 2012	October 1 – December 31, 2011	$0.69	$138

On April 24, 2012, the Company’s Board of Directors approved an increase in the quarterly cash distribution from $0.69 per unit to $0.725 per unit with respect to the first quarter of 2012, representing an increase of 5%. On October 23, 2012, the Company’s Board of Directors declared a cash distribution of $0.725 per unit, or $2.90 per unit on an annualized basis, with respect to the third quarter of 2012. The distribution, totaling approximately $170 million, will be paid on November 14, 2012, to unitholders of record as of the close of business on November 6, 2012.

Off-Balance Sheet Arrangements

The Company does not currently have any off-balance sheet arrangements.

Contingencies

The Company has been named as a defendant in a number of lawsuits, including claims from royalty owners related to disputed royalty payments and royalty valuations. The Company has established reserves that management currently believes are adequate to provide for potential liabilities based upon its evaluation of these matters. For a certain statewide class action royalty payment dispute where a reserve has not yet been established, the Company has denied that it has any liability on the claims and has raised arguments and defenses that, if accepted by the court, will result in no loss to the Company. Discovery related to class certification has concluded. Briefing and the hearing on class certification have been deferred by court order pending the Tenth Circuit Court of Appeals’ resolution of interlocutory appeals of two unrelated class certification orders. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any. In addition, the Company is involved in various other disputes arising in the ordinary course of business. The Company is not currently a party to any litigation or pending claims that it believes would have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

During the nine months ended September 30, 2012, and September 30, 2011, the Company made no significant payments to settle any legal, environmental or tax proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Commitments and Contractual Obligations

The Company has contractual obligations for long-term debt, operating leases and other long-term liabilities that were summarized in the table of contractual obligations in the 2011 Annual Report on Form 10-K. With the exception of the: (i) issuance of $1.8 billion in aggregate principal amount of 6.25% senior notes due November 2019; (ii) the $400 million future funding commitment associated with the joint-venture agreement entered into with Anadarko in April 2012; and (iii) an amendment to the Company's Credit Facility that extended the maturity date from April 2016 to April 2017, there have been no significant changes to the Company's contractual obligations from December 31, 2011. See Note 6 for additional information about the Company's debt instruments.

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Non-GAAP Financial Measures

The non-GAAP financial measures of adjusted EBITDA and adjusted net income, as defined by the Company, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP measures should be considered in conjunction with net income and other performance measures prepared in accordance with GAAP, such as operating income or cash flow from operating activities. Adjusted EBITDA and adjusted net income should not be considered in isolation or as a substitute for GAAP measures, such as net income, operating income or any other GAAP measure of liquidity or financial performance.

Adjusted EBITDA (Non-GAAP Measure)

Adjusted EBITDA is a measure used by Company management to indicate (prior to the establishment of any reserves by its Board of Directors) the cash distributions the Company expects to make to its unitholders. Adjusted EBITDA is also a quantitative measure used throughout the investment community with respect to publicly-traded partnerships and limited liability companies.

The Company defines adjusted EBITDA as net income (loss) plus the following adjustments:

- Net operating cash flow from acquisitions and divestitures, effective date through closing date;
- Interest expense;
- Depreciation, depletion and amortization;
- Impairment of long-lived assets;
- Write-off of deferred financing fees;
- (Gains) losses on sale of assets and other, net;
- Provision for legal matters;
- Loss on extinguishment of debt;
- Unrealized (gains) losses on commodity derivatives;
- Unrealized (gains) losses on interest rate derivatives;
- Realized (gains) losses on interest rate derivatives;
- Realized (gains) losses on canceled derivatives;
- Realized gain on recovery of bankruptcy claim;
- Unit-based compensation expenses;
- Exploration costs; and
- Income tax (benefit) expense.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Net income (loss)	$(430,005)	$837,627	$(199,121)	$628,054
Plus:				
Net operating cash flow from acquisitions and divestitures, effective date through closing date	36,520	1,521	81,647	37,880
Interest expense, cash	50,076	39,609	179,728	164,790
Interest expense, noncash	55,621	26,239	97,878	26,883
Depreciation, depletion and amortization	167,695	88,328	428,477	234,039
Impairment of long-lived assets	—	—	146,499	—
Write-off of deferred financing fees	—	—	7,889	1,189
(Gains) losses on sale of assets and other, net	(119)	167	872	(749)
Provision for legal matters	310	36	1,105	776
Loss on extinguishment of debt	—	—	—	94,372
Unrealized (gains) losses on commodity derivatives	520,007	(732,452)	269,601	(470,601)
Realized gains on canceled derivatives	—	(26,752)	—	(26,752)
Realized gain on recovery of bankruptcy claim	—	—	(18,277)	—
Unit-based compensation expenses	6,901	5,578	21,735	16,759
Exploration costs	390	503	1,207	1,498
Income tax (benefit) expense	(4,950)	2,862	4,480	8,730
Adjusted EBITDA	$402,446	$243,266	$1,023,720	$716,868

Adjusted Net Income (Non-GAAP Measure)

Adjusted net income is a performance measure used by Company management to evaluate its operational performance from oil and natural gas properties, prior to unrealized (gains) losses on derivatives, realized (gains) losses on canceled derivatives, realized gain on recovery of bankruptcy claim, impairment of long-lived assets, loss on extinguishment of debt and (gains) losses on sale of assets, net.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

The following presents a reconciliation of net income (loss) to adjusted net income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands, except per unit amounts)			
Net income (loss)	$(430,005)	$837,627	$(199,121)	$628,054
Plus:				
Unrealized (gains) losses on commodity derivatives	520,007	(732,452)	269,601	(470,601)
Realized gains on canceled derivatives	—	(26,752)	—	(26,752)
Realized gain on recovery of bankruptcy claim	—	—	(18,277)	—
Impairment of long-lived assets	—	—	146,499	—
Loss on extinguishment of debt	—	—	—	94,372
(Gains) losses on sale of assets, net	(155)	131	766	(855)
Adjusted net income	$89,847	$78,554	$199,468	$224,218
Net income (loss) per unit – basic	$(2.18)	$4.74	$(1.04)	$3.63
Plus, per unit:				
Unrealized (gains) losses on commodity derivatives	2.63	(4.15)	1.40	(2.73)
Realized gains on canceled derivatives	—	(0.15)	—	(0.15)
Realized gain on recovery of bankruptcy claim	—	—	(0.09)	—
Impairment of long-lived assets	—	—	0.75	—
Loss on extinguishment of debt	—	—	—	0.55
(Gains) losses on sale of assets, net	—	—	—	—
Adjusted net income per unit – basic	$0.45	$0.44	$1.02	$1.30

Regulatory Matters

On April 17, 2012, the Environmental Protection Agency (“EPA”) issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to the Company’s operations, including the installation of new equipment to control emissions. The Company is currently evaluating the effect these rules will have on its business.

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the nine months ended September 30, 2012, the Company did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of its facilities. The Company is not aware of any environmental issues or claims that will require material capital expenditures during 2012 or that will otherwise have a material impact on its financial position, results of operations or cash flows.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon the condensed consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and

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assumptions on a regular basis. The Company bases estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of financial statements.

Recently Issued Accounting Standards

For a discussion of recently issued accounting standards, see Note 1 of Notes to Condensed Consolidated Financial Statements.

Cautionary Statement

This Quarterly Report on Form 10-Q contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond the Company’s control. These statements may include content about the Company’s:

- business strategy;
- acquisition strategy;
- financial strategy;
- drilling locations;
- oil, natural gas and NGL reserves;
- realized oil, natural gas and NGL prices;
- production volumes;
- lease operating expenses, general and administrative expenses and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 2. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “continue,” the negative of su other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q are largely based on Company expectations, which reflect estimates and assumptions made by Company management. These estimates and assumptions reflect management’s best judgment based on currently known market conditions and other factors. Although the Company believes such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond its control. In addition, management’s assumptions may prove to be inaccurate. The Company cautions that the forward-looking statements contained in this Quarterly Report on Form 10-Q are not guarantees of future performance, and it cannot assure any reader that such statements will be realized or the forward-looking statements or events will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements due to factors set forth in Item 1A. “Risk Factors” in this Quarterly Report on Form 10-Q and in the Annual Report on Form 10-K for the year ended December 31, 2011, and elsewhere in the Annual Report. The forward-looking statements speak only as of the date made and, other than as required by law, the Company undertakes no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how the Company views and manages its ongoing market risk exposures. All of the Company’s market risk sensitive instruments were entered into for purposes other than trading.

The following should be read in conjunction with the financial statements and related notes included elsewhere in this Quarterly Report on Form 10-Q and in the Company’s 2011 Annual Report on Form 10-K. A reference to a “Note” herein refers to the accompanying Notes to Condensed Consolidated Financial Statements contained in Item 1. “Financial Statements.”

Commodity Price Risk

The Company enters into derivative contracts with respect to a portion of its projected production through various transactions that provide an economic hedge of the risk related to the future commodity prices received. The Company does not enter into derivative contracts for trading purposes (see Note 7). At September 30, 2012, the fair value of fixed price swaps and put contracts that settle during the next 12 months was a net asset of approximately $317 million. A 10% increase in the index oil and natural gas prices above the September 30, 2012, prices for the next 12 months would result in a net asset of approximately $142 million, which represents a decrease in the fair value of approximately $175 million; conversely, a 10% decrease in the index oil and natural gas prices would result in a net asset of approximately $501 million, which represents an increase in the fair value of approximately $184 million.

Interest Rate Risk

At September 30, 2012, the Company had long-term debt outstanding under its Credit Facility of approximately $2.0 billion, which incurred interest at floating rates (see Note 6). A 1% increase in the London Interbank Offered Rate (“LIBOR”) would result in an estimated $20 million increase in annual interest expense.

Counterparty Credit Risk

The Company accounts for its commodity derivatives at fair value on a recurring basis (see Note 8). The fair value of these derivative financial instruments includes the impact of assumed credit risk adjustments, which are based on the Company’s and counterparties’ published credit ratings, public bond yield spreads and credit default swap spreads, as applicable.

At September 30, 2012, the average public bond yield spread utilized to estimate the impact of the Company’s credit risk on derivative liabilities was approximately 3.37%. A 1% increase in the average public bond yield spread would result in an estimated $250,000 increase in net income for the nine months ended September 30, 2012. At September 30, 2012, the credit default swap spreads utilized to estimate the impact of counterparties’ credit risk on derivative assets ranged between 0% and 4.02%. A 1% increase in each of the counterparties’ credit default swap spreads would result in an estimated $10 million decrease in net income for the nine months ended September 30, 2012.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the Company's reports under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, and the Company's Audit Committee of the Board of Directors, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

The Company carried out an evaluation under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of its disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2012.

Changes in the Company's Internal Control Over Financial Reporting

The Company's management is also responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. The Company's internal controls were designed to provide reasonable assurance as to the reliability of its financial reporting and the preparation and presentation of the condensed consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

There were no changes in the Company's internal controls over financial reporting during the third quarter of 2012 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

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Part II - Other Information

Item 1. Legal Proceedings

For a discussion of general legal proceedings, see Note 10 of Notes to Condensed Consolidated Financial Statements.

Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial position, results of operations, liquidity or the trading price of our units are described in Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2011. As of the date of this report, these risk factors have not changed materially. This information should be considered carefully, together with other information in this report and other reports and materials we file with the U.S. Securities and Exchange Commission ("SEC").

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100 million of the Company's outstanding units from time to time on the open market or in negotiated purchases. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. The Company did not repurchase any units during the nine months ended September 30, 2012. At September 30, 2012, approximately $56 million was available for unit repurchase under the program.

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

Not applicable

Item 5. Other Information

On October 17, 2012, LinnCo, LLC ("LinnCo"), a wholly owned subsidiary of LINN Energy at September 30, 2012, completed its initial public offering of 34,787,500 common shares representing limited liability company interests. LinnCo has elected to be taxed as a corporation, and accordingly, its shareholders will receive a Form 1099 in respect of any dividends paid by LinnCo. The net proceeds from the offering were used to acquire 34,787,500 LINN Energy units which are equal to the number of LinnCo shares sold in the offering. LinnCo will have no assets or operations other than those related to its ownership of LINN Energy units. The Company used the proceeds it received from the sale of its units to LinnCo to pay the expenses of the offering and repay a portion of the outstanding indebtedness under its Credit Facility. LinnCo's shares are listed on the NASDAQ Global Select Market under the symbol "LNCO."

The Company is a limited liability company and its units representing limited liability company interests ("units") are listed on the NASDAQ Global Select Market. The SEC's taxonomy for interactive data reporting does not contain tags that include the term "units" for all existing equity accounts; therefore, in certain instances, the Company has used tags that refer to "shares" or "stock" rather than "units" in its interactive data exhibit. These tags were selected to enhance comparability between the Company and its peers and it should not be inferred from the usage of these tags that an investment in the Company is in any form other than "units" as described above. The Company's interactive data files are included as Exhibit 101 to this Quarterly Report on Form 10-Q.

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Item 6. Exhibits

Exhibit Number		Description
10.1	—	Fourth Amendment to the Fifth Amended and Restated Credit Agreement among Linn Energy, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders and agents party thereto (incorporated herein by reference to Exhibit 10.31 to Amendment No. 5 to Registration Statement on Form S-1/A filed on October 10, 2012)
31.1*	—	Section 302 Certification of Mark E. Ellis, Chairman, President and Chief Executive Officer of Linn Energy, LLC
31.2*	—	Section 302 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
32.1*	—	Section 906 Certification of Mark E. Ellis, Chairman, President and Chief Executive Officer of Linn Energy, LLC
32.2*	—	Section 906 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
101.INS**	—	XBRL Instance Document
101.SCH**	—	XBRL Taxonomy Extension Schema Document
101.CAL**	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	—	XBRL Taxonomy Extension Presentation Linkbase Document

*Filed herewith.

**Furnished herewith.

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SIGNATURE

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.

LINN ENERGY, LLC
(Registrant)

Date: October 25, 2012

/s/ David B. Rottino
David B. Rottino
Senior Vice President of Finance, Business Development and Chief Accounting Officer
(As Duly Authorized Officer and Chief Accounting Officer)