LRR Energy, L.P.
Form 10-Q
November 08, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

o 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: 001-35344

LRR Energy, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**90-0708431** (I.R.S. Employer Identification No.)
Heritage Plaza **1111 Bagby, Suite 4600** **Houston, Texas** (Address of principal executive offices)	**77002** (Zip code)

Telephone Number: (713) 292-9510

(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 o

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

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 o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company o

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

There were 15,708,474 Common Units, 6,720,000 Subordinated Units and 22,400 General Partner Units outstanding as of November 5, 2012. The Common Units trade on the New York Stock Exchange under the ticker symbol LRE .

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements.

LRR Energy, L.P.

Consolidated Condensed Balance Sheets

(Unaudited)

(in thousands, except unit amounts)

	Partnership			
		September 30, 2012		December 31, 2011
ASSETS				
Current assets:				
Cash and cash equivalents	$	6,301	$	1,513
Accounts receivable		8,033		12,924
Commodity derivative instruments		15,461		16,064
Amounts due from affiliates		2,465		
Prepaid expenses		520		578
Total current assets		32,780		31,079
Property and equipment (successful efforts method)		752,640		725,486
Accumulated depletion, depreciation and impairment		(295,112)		(263,931)
Total property and equipment, net		457,528		461,555
Commodity derivative instruments		20,155		27,015
Deferred financing costs, net of accumulated amortization		1,664		1,365
TOTAL ASSETS	$	512,127	$	521,014
LIABILITIES AND UNITHOLDERS EQUITY				
Current liabilities:				
Trade accounts payable	$		$	2,707
Accrued liabilities		3,102		2,746
Accrued capital cost		2,381		1,421
Amounts due to affiliates				536
Commodity derivative instruments		1,669		186
Interest rate derivative instruments		669		
Asset retirement obligations		376		359
Total current liabilities		8,197		7,955
Long-term liabilities:				
Commodity derivative instruments		1,458		
Interest rate derivative instruments		3,502		
Term loan		50,000		
Revolving credit facility		183,000		155,800
Asset retirement obligations		24,857		23,795
Deferred tax liabilities		141		35
Total long-term liabilities		262,958		179,630
Total liabilities		271,155		187,585
Unitholders equity:				

Predecessor s capital				61,926
General partner (22,400 units issued and outstanding as of September 30, 2012 and December 31, 2011)		406		438
Public common unitholders (10,608,000 units issued and outstanding as of September 30, 2012 and December 31, 2011)		175,164		189,537
Affiliated common unitholders (5,049,600 units issued and outstanding as of September 30, 2012 and December 31, 2011)		28,087		35,007
Subordinated unitholders (6,720,000 units issued and outstanding as of September 30, 2012 and December 31, 2011)		37,315		46,521
Total unitholders equity		240,972		333,429
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$	512,127	$	521,014

See accompanying notes to the unaudited consolidated/combined condensed financial statements

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LRR Energy, L.P.

Condensed Statements of Operations

(Unaudited)

(in thousands, except per unit amounts)

	Partnership Three Months Ended September 30, 2012 (consolidated)	Predecessor Three Months Ended September 30, 2011 (combined)	Partnership Nine Months Ended September 30, 2012 (consolidated)	Predecessor Nine Months Ended September 30, 2011 (combined)
Revenues:				
Oil sales	$ 16,502	$ 16,677	$ 47,415	$ 51,338
Natural gas sales	5,691	9,699	15,477	31,453
Natural gas liquids sales	2,633	4,508	8,403	12,266
Realized gain (loss) on commodity derivative instruments	5,808	6,029	17,876	6,070
Unrealized gain (loss) on commodity derivative instruments	(21,463)	29,253	(10,455)	26,144
Other income	30	42	33	122
Total revenues	9,201	66,208	78,749	127,393
Operating expenses:				
Lease operating expense	6,919	6,797	20,127	18,732
Production and ad valorem taxes	1,987	2,711	5,348	5,731
Depletion and depreciation	8,267	11,163	28,126	32,034
Impairment of oil and natural gas properties	451	16,765	3,544	16,765
Accretion expense	369	368	1,086	1,112
(Gain) loss on settlement of asset retirement obligations	94	39	(14)	39
Management fees		1,579		4,546
General and administrative expense	2,294	1,208	8,595	4,414
Total operating expenses	20,381	40,630	66,812	83,373
Operating income (loss)	(11,180)	25,578	11,937	44,020
Other income (expense), net				
Interest income				1
Interest expense	(2,081)	(255)	(4,541)	(814)
Realized loss on interest rate derivative instruments	(153)	(141)	(294)	(439)
Unrealized gain (loss) on interest rate derivative instruments	(2,124)	134	(4,171)	297
Other income (expense), net	(4,358)	(262)	(9,006)	(955)
Income (loss) before taxes	(15,538)	25,316	2,931	43,065
Income tax benefit (expense)	(20)	266	(170)	120
Net income (loss)	$ (15,558)	$ 25,582	$ 2,761	$ 43,185
Net income (loss) attributable to predecessor operations			(2,265)	
	$ (15,558)		$ 496	

Net income (loss) available to unitholders				
Computation of net income (loss) per limited partner unit:				
General partners interest in net income (loss)	$	(16)	$	
Limited partners interest in net income (loss)	$	(15,542)	$	496
Net income (loss) per limited partner unit (basic and diluted)	$	(0.69)	$	0.02
Weighted average number of limited partner units outstanding		22,428		22,426

See accompanying notes to the unaudited consolidated/combined condensed financial statements

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LRR Energy, L.P.

Consolidated Condensed Statement of Changes in Unitholders Equity

(Unaudited)

(in thousands)

			Limited Partners			
				Affiliated		
	Predecessors Capital	General Partner	Public Common	Common	Subordinated	Total
Balance, December 31, 2011	$ 61,926	$ 438	$ 189,537	$ 35,007	$ 46,521	$ 333,429
Contribution from predecessor	(4,869)	(5)	(2,241)	(1,061)	(1,409)	(9,585)
Book value of transferred properties contributed by predecessor	(59,322)					(59,322)
Amortization of equity awards			231			231
Distribution		(27)	(12,599)	(5,971)	(7,945)	(26,542)
Net income	2,265		236	112	148	2,761
Balance, September 30, 2012	$	$ 406	$ 175,164	$ 28,087	$ 37,315	$ 240,972

See accompanying notes to the unaudited consolidated/combined condensed financial statements

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LRR Energy, L.P.

Condensed Statements of Cash Flows

(Unaudited)

(in thousands)

	Partnership Nine Months Ended September 30, 2012 (consolidated)	Predecessor Nine Months Ended September 30, 2011 (combined)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 2,761	$ 43,185
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion and depreciation	28,126	32,034
Impairment of oil and natural gas properties	3,544	16,765
Unrealized (gain) loss on derivative instruments, net	14,626	(26,441)
Accretion expense	1,086	1,112
Amortization of equity awards	231	
Amortization of deferred financing costs and other	270	59
(Gain) loss on settlement of asset retirement obligations	(14)	39
Purchase of derivative contracts	(59)	
Changes in operating assets and liabilities:		
Change in receivables	4,891	19
Change in prepaid expenses	58	484
Change in trade accounts payable and accrued liabilities	(2,245)	2,665
Change in amounts due from affiliates	(3,001)	255
Net cash provided by operating activities	50,274	70,176
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of oil and natural gas properties	(1,008)	(390)
Development of oil and natural gas properties	(25,652)	(42,210)
Disposition of oil and gas properties		2,956
Expenditures for other property and equipment	(16)	(45)
Net cash used in investing activities	(26,676)	(39,689)
CASH FLOWS FROM FINANCING ACTIVITIES		
Capital contributions		5,353
Contribution to Fund I	(4,869)	
Deferred financing costs	(561)	
Borrowings under revolving credit facility	77,200	
Payments on revolving credit facility	(50,000)	
Borrowings under term loan	50,000	
Distribution to Fund I	(64,038)	
Distributions to unitholders	(26,542)	(42,579)
Net cash used in financing activities	(18,810)	(37,226)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	4,788	(6,739)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	1,513	12,455
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 6,301	$ 5,716

Supplemental disclosure of non-cash items to reconcile investing and financing activities				
Property and equipment:				
Change in accrued capital costs	$	960	$	1,531
Asset retirement obligations		(257)		84

See accompanying notes to the unaudited consolidated/combined condensed financial statements

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LRR Energy, L.P.

Notes to Consolidated/Combined Condensed Financial Statements

(unaudited)

1. Description of Business

LRR Energy, L.P. (we, us, our, or the Partnership) is a Delaware limited partnership formed in April 2011 by Lime Rock Management LP (Li Rock Management), an affiliate of Lime Rock Resources A, L.P. (LRR A), Lime Rock Resources B, L.P. (LRR B) and Lime Rock Resources C, L.P. (LRR C), to operate, acquire, exploit and develop producing oil and natural gas properties in North America with long-lived, predictable production profiles. As used herein, references to Fund I or predecessor refer collectively to LRR A, LRR B and LRR C. References to Lime Rock Resources refer collectively to LRR A, LRR B, LRR C, Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. The properties conveyed to us in connection with our initial public offering (IPO) on November 16, 2011 (such conveyance described below) are located in the Permian Basin region in West Texas and southeast New Mexico, the Mid-Continent region in Oklahoma and East Texas and the Gulf Coast region in Texas. We conduct our operations through our wholly owned subsidiary, LRE Operating, LLC (OLLC).

Prior to our IPO, Fund I owned 100% of the properties conveyed to us in connection with our IPO. At the closing of our IPO, we entered into a purchase, sale, contribution, conveyance and assumption agreement with Fund I pursuant to which Fund I sold and contributed to us specified oil and natural gas properties and related net profits interests and operations and certain commodity derivative contracts (the Partnership Properties). Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and our assumption of $27.3 million of LRR A s indebtedness.

After reviewing applicable accounting literature, we consider the Partnership Properties to be under common control with Fund I. We have presented the combined historical financial statements of Fund I as our historical financial statements because we believe them to be informative to our investors and representative of our management s ability to manage the Partnership Properties. The financial data and operations of Fund I are referred to herein as predecessor.

The following table presents the net assets conveyed by Fund I to the Partnership immediately prior to the closing of our IPO including the debt assumption (in thousands):

Property and equipment, net	$	400,056
Derivative instruments		36,705
Total assets	$	436,761
Long-term debt	$	27,251
Derivative instruments		476
Asset retirement obligations		22,673
Total liabilities	$	50,400
Net assets	$	386,361

On June 1, 2012, we completed an acquisition from Fund I of certain oil and natural gas properties (the Transferred Properties) located in the Permian Basin region of New Mexico and onshore Gulf Coast region of Texas for $65.1 million in cash (the Transaction). The Transaction was effective as of March 1, 2012. We funded the acquisition with borrowings under our revolving credit facility (Note 7). In September 2012, we received $1.1 million in cash from Fund I related to post-closing adjustments to the purchase price for the acquisition. Please refer to Notes 2 and 3 regarding the recast of financial information for transactions between entities under common control.

The following table presents the net assets conveyed by Fund I to us in the Transaction (in thousands):

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Property and equipment, net	$	60,365
Asset retirement obligations and other liabilities		(1,043)
Net assets	$	59,322

2. Summary of Significant Accounting Policies

Our accounting policies are set forth in Note 2 of the audited consolidated/combined financial statements in our Annual Report on Form 10-K for the year ended December 31, 2011, and are supplemented by the notes to these unaudited consolidated/combined condensed financial statements. There have been no significant changes to these policies other than noted below, and these unaudited consolidated/combined condensed financial statements should be read in conjunction with the audited consolidated/combined financial statements and notes in our Annual Report on Form 10-K for the year ended December 31, 2011.

Basis of Presentation

These interim financial statements are unaudited and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) regarding interim financial reporting. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America (GAAP) for complete consolidated/combined financial statements and should be read in conjunction with the audited consolidated/combined financial statements in our Annual Report on Form 10-K for the year ended December 31, 2011. While the year-end balance sheet data was derived from audited financial statements, this interim report does not include all disclosures required by GAAP for annual periods. These unaudited interim consolidated/combined financial statements reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for the periods presented.

In the third quarter of 2012, we recorded an adjustment to correct an error in our calculation of depletion and depreciation expense related to a previous accounting period. The net impact of the adjustment was an increase to pre-tax income and net income of $1.9 million for the three months ended September 30, 2012. The error occurred in the three months ended June 30, 2012; as such, the financial statements for th nine months ended September 30, 2012 were not impacted by the adjustment. We do not believe this adjustment is material to our unaudited condensed consolidated financial statements for the three months ended September 30, 2012 or our expected 2012 annual financial results.

Because Fund I owns 5,049,600 common units and all of our 6,720,000 subordinated units, representing an aggregate 52.4% limited partner interest in us, each acquisition of assets from Fund I is considered a transaction between entities under common control. As a result, we are required to revise our financial statements to include the activities of the Transferred Properties.

Accordingly, our historical financial statements previously filed with the SEC have been revised in this Quarterly Report on Form 10-Q to include the results attributable to the Transferred Properties as if the Partnership owned such assets for all periods presented in 2012 and 2011. The consolidated financial statements for periods prior to our acquisition of the Transferred Properties have been prepared from our predecessor s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the assets during the periods reported. See our accounting policy below under Transactions Between Entities Under Common Control.

Net income attributable to the Transferred Properties for periods prior to the Partnership s acquisition of such assets was not available for distribution to our unitholders. Therefore, this income was not allocated to the limited partners for the purpose of calculating net income per common unit.

Revised Balance Sheet. Our historical balance sheet as of December 31, 2011 was impacted based on revisions from the Transferred Properties by an increase in total assets of $62.9 million which primarily represented increases to our property, plant and equipment. Total liabilities and partners capital was also increased by $62.9 million,

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comprised of increases of less than $0.1 million in current liabilities, $1.0 million in noncurrent liabilities and $61.9 million in partners capital.

Revised Statements of Operations. Our statements of operations for the nine months ended September 30, 2012 were impacted based on revisions from the Transferred Properties by an increase in net income of $2.3 million.

Transactions Between Entities Under Common Control

Master limited partnerships (MLPs) enter into transactions whereby the MLP receives a transfer of certain assets from its sponsor or predecessor for consideration of either cash, units, assumption of debt, or any combination thereof. We account for the net assets received using the carryover book value of the predecessor as these are transactions between entities under common control. Our historical financial statements have been revised to include the results attributable to the assets contributed from Fund I as if we owned such assets for all periods presented by us. The following financial statement items were impacted:

Oil and Natural Gas Properties Received. The book value and related activity of oil and natural gas properties received from our predecessor is determined using the carrying value of the specific assets contributed.

Asset Retirement Obligations Received. The book value and related activity of asset retirement obligations received from our predecessor was determined by using the carrying value of the specific liabilities attributable to the assets contributed.

Oil, Natural Gas and NGL Revenues and Expenses. Oil, natural gas and NGL revenues and expenses related to the Transferred Properties are based on the actual results of the Transferred Properties. Historical lease operating statements by individual asset were used as the basis for revenues and direct operating expenses.

General and Administrative Expense. The general and administrative expense attributable to the Transferred Properties was determined by the ratio of production for the Transferred Properties to our total predecessor s production for the period presented.

Recent Accounting Pronouncements

In May 2011, the FASB issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. The Amendments explain how to measure fair value and change the wording used to describe many of the fair value requirements in GAAP, but do not require additional fair value measurements. The guidance became effective for interim and annual periods beginning on or after December 15, 2011. We adopted these amendments on January 1, 2012 and they did not have a material impact on our consolidated financial position, results of operations or cash flows.

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities. The amendments in this update require enhanced disclosures around financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

3. Acquisitions and Divestitures

Acquisitions Between Entities Under Common Control

On June 1, 2012, we completed the acquisition of the Transferred Properties from Fund I for a total purchase price of $65.1 million, after giving effect to purchase price adjustments from the effective date of the Transaction (March 1, 2012). The post closing adjustments to the purchase price for the acquisition were finalized in September 2012, and we received $1.1 million in cash from Fund I. We financed the Transaction with borrowings under our

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existing credit facility as discussed in Note 7. The net assets were recorded using carryover book value of Fund I as the acquisition was a transaction between entities under common control. Our historical financial statements were revised to include the results attributable to the Transferred Properties as if we owned the properties for all periods presented in our consolidated condensed financial statements. See Note 2 for further disclosures regarding the Transaction.

Divestitures

We did not divest any significant properties during the nine months ended September 30, 2012 or 2011.

4. Fair Value Measurements

Our financial instruments, including cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. Our financial and non-financial assets and liabilities that are measured on a recurring basis are measured and reported at fair value.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of fair value hierarchy are as follows:

Level 1 Defined as inputs such as unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 Defined as inputs other than quoted prices in active markets that are either directly or indirectly observable for the asset or liability.

Level 3 Defined as unobservable inputs for use when little or no market data exists, requiring an entity to develop its own assumptions for the asset or liability.

As required by GAAP, we utilize the most observable inputs available for the valuation technique used. The financial assets and liabilities are classified in their entirety based on the lowest level of input that is of significance to the fair value measurement. The following table describes, by level within the hierarchy, the fair value of our financial assets and liabilities that were accounted for at fair value on a recurring basis as of the date indicated (in thousands).

	Level 1	Level 2	Level 3	Total
September 30, 2012				
Assets:				
Commodity derivative instruments	$	$ 35,616	$	$ 35,616
Liabilities:				
Commodity derivative instruments		3,127		3,127
Interest rate derivative instruments		4,171		4,171

	Level 1	Level 2	Level 3	Total
December 31, 2011				
Assets:				
Commodity derivative instruments	$	$	$ 43,079	$ 43,079
Liabilities:				
Commodity derivative instruments			186	186

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All fair values reflected in the table above and on the unaudited consolidated condensed balance sheets have been adjusted for non-performance risk. The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Commodity Derivative Instruments The fair value of the commodity derivative instruments is estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services reflecting broker market quotes.

Interest Rate Derivative Instruments The fair value of the interest rate derivative instruments is estimated using a combined income and market valuation methodology based upon forward interest rates and volatility curves. The curves are obtained from independent pricing services reflecting broker market quotes. We did not have any outstanding interest rate derivative instruments at December 31, 2011.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the three and nine months ended September 30, 2012 and 2011 (in thousands):

	Partnership Three Months Ended September 30, 2012	**Predecessor Three Months Ended September 30, 2011**	**Partnership Nine Months Ended September 30, 2012**	**Predecessor Nine Months Ended September 30, 2011**
Balance at beginning of period	$	$ 20,558	$ 42,893	$ 23,504
Total gains or losses (realized or unrealized): Included in earnings		35,275		32,072
Settlements		(5,888)		(5,631)
Transfers in and out of Level 3 (1)			(42,893)	
Balance at end of period	$	$ 49,945	$	$ 49,945
Changes in unrealized gains (losses) relating to derivatives still held at end of period	$ (23,587)	$ 29,387	$ (14,626)	$ 26,441

(1) As part of a review of our fair value financial statement disclosures in light of ASU 2011-04, management has determined, effective January 1, 2012, the fair values of our derivative instruments should be classified as Level 2. Management has determined the prices quoted by the independent pricing service are observable inputs that management is able to independently test and corroborate for reasonableness through market prices. Accordingly, on January 1, 2012, we transferred all derivative instruments which are measured on a recurring basis from Level 3 into Level 2.

5. Property and Equipment

The following table sets forth the components of property and equipment, net (in thousands):

	September 30, 2012	December 31, 2011
Oil and natural gas properties (successful efforts method)	$ 751,104	$ 723,505
Unproved properties	1,218	1,679
Other property and equipment	318	302
	752,640	725,486
Accumulated depletion, depreciation and impairment	(295,112)	(263,931)
Total property and equipment, net	$ 457,528	$ 461,555

We perform an impairment analysis of our oil and natural gas properties on a quarterly basis due to the volatility in commodity prices. For the three and nine months ended September 30, 2012, we recorded non-cash impairment charges of approximately $0.5 million and $3.5 million, respectively, to impair the value of our unproved properties and proved oil and natural gas properties in the Mid-Continent region. For each of the three and nine months ended September 30, 2011, we recorded non-cash impairment charges of approximately $16.8 million in the Mid-Continent region.

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The impairment of proved oil and natural gas properties was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in an internal reserve report. This report was based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 3 inputs. 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. The underlying commodity prices embedded in our estimated cash flows are the product of a process that begins with New York Mercantile Exchange (NYMEX) forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Furthermore, significant assumptions in valuing the proved reserves included the reserve quantities, anticipated drilling and operating costs, anticipated production taxes, future expected oil and natural gas prices and basis differentials, anticipated drilling schedules, anticipated production declines, and an appropriate discount rate commensurate with the risk of the underlying cash flow estimates. Cash flow estimates for the impairment testing excluded derivative instruments used to mitigate the risk of lower future oil and natural gas prices. Significant assumptions in valuing the unproved reserves included the evaluation of the probable and possible reserves included in the internal reserve report, future expected oil and natural gas prices and basis differentials, and our anticipated drilling schedules.

The asset impairment had no impact on our cash flows, liquidity position, or debt covenants. If future oil or natural gas prices decline further, the estimated undiscounted future cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for our recently acquired properties and a non-cash impairment charge may be required to be recognized in future periods.

6. Asset Retirement Obligations

The following is a summary of our ARO as of and for the nine months ended September 30, 2012 (in thousands):

Beginning of period	$	24,154
Revisions to previous estimates		(133)
Liabilities incurred		257
Liabilities settled		(131)
Accretion expense		1,086
End of period		25,233
Less: Current portion of asset retirement obligations		(376)
Asset retirement obligations non-current	$	24,857

7. Long-Term Debt

Credit Agreement

In July 2011, subject to consummation of our IPO, we, as guarantor, and our wholly owned subsidiary, OLLC, as borrower, entered into a five-year, $500 million senior secured revolving credit facility, as amended, (the Credit Agreement) that matures in July 2016. The Credit Agreement is reserve-based and we are permitted to borrow under our credit facility an amount up to the borrowing base, which was $240 million as of September 30, 2012. Our borrowing base, which is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders at their sole discretion. Unanimous approval by the lenders is required for any increase to the borrowing base.

Borrowings under the Credit Agreement are secured by liens on at least 80% of the PV-10 value of our and our subsidiaries oil and natural gas properties and all of our equity interests in the OLLC and any future guarantor subsidiaries and all of our and our subsidiaries other assets including personal property. Borrowings under the Credit Agreement bear interest, at OLLC s option, at either (i) the greater of the prime rate as determined by the Administrative Agent, the federal funds effective rate plus 0.50%, and the 30-day adjusted LIBOR plus 1.0%, all of which is subject to a margin that varies from 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letter of credit exposure to the borrowing base then in effect), or (ii) the applicable reserve-adjusted LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

The Credit Agreement requires us to maintain a leverage ratio of Total Debt to EBITDAX (as each term is defined in the Credit Agreement) of not more than 4.0 to 1.0x, and a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0x.

Additionally, the Credit Agreement contains various covenants and restrictive provisions which limit our, OLLC s and any of our subsidiaries ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production; and prepay certain indebtedness. As of September 30, 2012, we were in compliance with all covenants contained in the Credit Agreement.

We expect that our borrowing base will be redetermined by our lending group during the month of November. We currently do not expect any changes to our borrowing base that would materially impact our operations, capital program, or our ability to make quarterly cash distributions to our unitholders at currently anticipated levels.

Term Loan Agreement

On June 28, 2012, we, as parent guarantor, and our wholly owned subsidiary, OLLC, as borrower, entered into a Second Lien Credit Agreement (the Term Loan Agreement). The Term Loan Agreement provides for a $50 million senior secured second lien term loan to OLLC. OLLC borrowed $50 million under the Term Loan Agreement and used the borrowings to repay outstanding borrowings under the Credit Agreement.

The obligations under the Term Loan Agreement are guaranteed on a joint and several basis by us. The obligations are secured by a second priority mortgage and security interest in all assets of OLLC and us that secure OLLC s and our existing indebtedness under the Credit Agreement.

Borrowings under the Term Loan Agreement mature on January 20, 2017, and, subject to the terms of the Intercreditor Agreement (as described below), OLLC has the ability at any time to prepay the Term Loan Agreement without premium or penalty. Borrowings under the Term Loan Agreement bear interest, at OLLC s option, at either

- the greatest of (i) the prime rate as defined in the Term Loan Agreement, (ii) the federal funds effective rate plus 0.50% and (iii) the 30-day adjusted LIBOR plus 1.0%, all of which is subject to an applicable margin as follows:

- 4.50% through March 31, 2013;
- 6.00% from April 1, 2013 to December 31, 2013; and
- 7.50% from January 1, 2014 to January 20, 2017; or

- the applicable reserve-adjusted LIBOR plus an applicable margin as follows:

- 5.50% through March 31, 2013;
- 7.00% from April 1, 2013 to December 31, 2013; and
- 8.50% from January 1, 2014 to January 20, 2017.

Additionally, the Term Loan Agreement provides for an upfront fee of one percent of the aggregate maximum commitment amount, or $500,000.

The Term Loan Agreement contains various covenants and restrictive provisions which limit the ability of OLLC, us or any of our subsidiaries to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of its assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of production; prepay certain indebtedness; and amend the Credit Agreement or grant any liens to secure any indebtedness under the Credit Agreement.

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The Term Loan Agreement also contains covenants that, among other things, require OLLC and us to maintain specified ratios including leverage ratio of Total Debt to EBITDAX of not more than 4.25 to 1.00x; a current ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0x; and an asset coverage ratio of Total Proved PV-10 to Total Debt of not less than 1.50 to 1.00x. As of September 30, 2012, we were in compliance with all covenants contained in the Term Loan Agreement.

The obligations under the Term Loan Agreement and the Credit Agreement are governed by an Intercreditor Agreement with OLLC as borrower and the Partnership as parent guarantor, which (i) provides that any liens on the assets and properties of OLLC, the Partnership or any of their subsidiaries securing the indebtedness under the Term Loan Agreement are subordinate to liens on the assets and properties of OLLC, the Partnership or any of their subsidiaries securing indebtedness under the Credit Agreement and derivative contracts with lenders and their affiliates and (ii) sets forth the respective rights, obligations and remedies of the lenders under the Credit Agreement with respect to their first-priority liens and the lenders under the Term Loan Agreement with respect to their second-priority liens.

As of September 30, 2012, we had approximately $233.0 million of outstanding debt and accrued interest was approximately $0.2 million. As of December 31, 2011, we had approximately $155.8 million of outstanding debt and accrued interest was approximately $0.5 million. Our outstanding debt increased primarily due to our June 2012 acquisition of oil and natural gas properties from Fund I for approximately $65.1 million and working capital borrowings.

Interest expense for the three months and nine months ended September 30, 2012 was approximately $2.1 million and $4.5 million, respectively. Interest expense for the three and nine months ended September 30, 2011 was approximately $0.3 million and $0.8 million, respectively. Interest expense for the 2011 periods is related to LRR A s credit facility. As of September 30, 2012 and December 31, 2011, our weighted average interest rate on our outstanding indebtedness was 3.70% and 2.86%, respectively. Please refer to Note 8 below for a discussion of our interest rate derivative contracts.

8. Derivatives

Objective and strategy We are exposed to commodity price and interest rate risk and consider it prudent to periodically reduce our exposure to cash flow variability resulting from commodity price changes and interest rate fluctuations. Accordingly, we enter into derivative instruments to manage our exposure to commodity price fluctuations, locational differences between a published index and the NYMEX futures on natural gas or crude oil productions, and interest rate fluctuations.

At September 30, 2012 and December 31, 2011, our open positions consisted of contracts such as (i) crude oil and natural gas financial collar contracts, (ii) crude oil, NGL and natural gas financial swaps, (iii) natural gas basis financial swaps, (iv) crude oil and natural gas puts and (v) interest rate swap agreements. Our derivative instruments are with the counterparties that are also lenders in our Credit Agreement.

Swaps and options are used to manage our exposure to commodity price risk and basis risk inherent in our oil and natural gas production. Commodity price swap agreements are used to fix the price of expected future oil and natural gas sales at major industry trading locations such as Henry Hub Louisiana (HH) for gas and Cushing Oklahoma (WTI) for oil. Basis swaps are used to fix the price differential between the product price at one location versus another. Options are used to establish a floor and a ceiling price (collar) for expected oil or gas sales. Interest rate swaps are used to fix interest rates on existing indebtedness.

Under commodity swap agreements, we exchange a stream of payments over time according to specified terms with another counterparty. Specifically for commodity price swap agreements, we agree to pay an adjustable or floating price tied to an agreed upon index for the commodity, either gas or oil, and in return receive a fixed price based on notional quantities. Under basis swap agreements, we agree to pay an adjustable or floating price tied to two agreed upon indices for gas and in return receive the differential between a floating index and fixed price based on notional quantities. A collar is a combination of a put purchased by us and a call option written by us. In a typical collar transaction, if the floating price based on a market index is below the floor price, we receive from the

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counterparty an amount equal to this difference multiplied by the specified volume, effectively a put option. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty an amount equal to the difference multiplied by the specific quantity, effectively a call option.

The interest rate swap agreements effectively fix our interest rate on amounts borrowed under the credit facility. The purpose of these instruments is to mitigate our existing exposure to unfavorable interest rate changes. Under interest rate swap agreements, we pay a fixed interest rate payment on a notional amount in exchange for receiving a floating amount based on LIBOR on the same notional amount.

We elected not to designate any positions as cash flow hedges for accounting purposes and, accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in the statements of operations. We record our derivative activities on a mark-to-market or fair value basis. Fair values are based on pricing models that consider the time value of money and volatility and are comparable to values obtained from counterparties. Pursuant to the accounting standard that permits netting of assets, liabilities, and collateral where the right of offset exists, we present the fair value of derivative financial instruments on a net basis.

At September 30, 2012, we had the following open commodity derivative contracts:

	Index	2012	2013	2014	2015	2016	2017
Natural gas positions							
Price swaps (MMBTUs)	NYMEX-HH	1,067,511	7,267,590	5,876,099	5,326,561	4,878,990	2,558,556
Weighted average price		$ 5.70	$ 5.15	$ 5.52	$ 5.71	$ 4.28	$ 4.54
Basis swaps (MMBTUs)	NYMEX	1,697,238	5,928,340	5,242,959	4,707,727	95,710	
Weighted average price		$ (0.1114)	$ (0.1432)	$ (0.1559)	$ (0.1698)	$ (0.1087)	$
Collars (MMBTUs)	NYMEX-HH	697,429					
Floor-Ceiling price		$ 4.75/7.31	$	$	$	$	$
Puts (MMBTUs)	NYMEX-HH	96,635	178,710				
Strike price		$ 2.00	$ 3.00	$	$	$	$
Oil positions							
Price swaps (BBLs)	NYMEX-WTI	151,045	620,772	460,926	398,253	352,804	
Weighted average price		$ 98.31	$ 95.19	$ 96.29	$ 94.49	$ 85.94	$
Puts (BBLs)	NYMEX-WTI	4,085					
Strike price		$ 70.00	$	$	$	$	$
NGL positions							
Price swaps (BBLs)	Mont Belvieu	45,598	144,323				
Weighted average price		$ 51.29	$ 50.49	$	$	$	$

At December 31, 2011, we had the following open commodity derivative contracts:

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	Index	2012	2013	2014	2015
Natural gas positions					
Price swaps (MMBTUs)	NYMEX-HH	3,684,189	5,757,645	5,107,055	4,596,205
Weighted average price		$ 6.21	$ 5.59	$ 5.76	$ 5.96
Collars (MMBTUs)	NYMEX-HH	2,902,801			
Floor-Ceiling price		$ 4.75-7.31	$	$	$
Oil positions					
Price swaps (BBLs)	NYMEX-WTI	251,005	289,323	248,149	219,657
Weighted average price		$ 102.20	$ 101.30	$ 100.01	$ 98.90
NGL positions					
Price swaps (BBLs)	Mont Belvieu	164,220			
Weighted average price		$ 49.92	$	$	$

At September 30, 2012, we had the following interest rate swap derivative contracts (in thousands):

Effective	Maturity	Notional Amount	Average %	Index
February 2012	February 2015	$ 150,000	0.5175%	LIBOR
February 2015	February 2017	75,000	1.7250%	LIBOR
February 2015	February 2017	75,000	1.7275%	LIBOR
June 2012	June 2015	70,000	0.52375%	LIBOR
June 2015	June 2017	70,000	1.4275%	LIBOR

We did not have any outstanding interest rate swap derivative contracts as of December 31, 2011.

Effect of Derivative Instruments Balance Sheet

The fair value of our commodity and interest rate derivative instruments as of September 30, 2012 is included in the table below (in thousands):

	As of September 30, 2012			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$	$ 669	$ 3,502
Sale of natural gas production				
Price swaps	10,355	16,112	381	1,054
Basis swaps			218	404
Collars	1,001			
Sale of crude oil production				
Price swaps	2,636	3,786	1,070	
Sale of NGLs				
Price swaps	1,469	257		

	$	15,461	$	20,155	$	2,338	$	4,960

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The fair value of our commodity derivative instruments as of December 31, 2011 is included in the table below (in thousands):

	As of December 31, 2011			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Sale of natural gas production				
Price swaps	$ 10,762	$ 22,190	$	$
Collars	4,464			
Sale of crude oil production				
Price swaps	838	4,825		
Sale of NGLs				
Price swaps			186	
	$ 16,064	$ 27,015	$ 186	$

Effect of Derivative Instruments   Statement of Operations

The unrealized and realized gain or loss amounts and classification related to derivative instruments for the three and nine months ended September 30, 2012 and 2011 are as follows (in thousands):

	Partnership Three Months Ended September 30, 2012	Predecessor Three Months Ended September 30, 2011	Partnership Nine Months Ended September 30, 2012	Predecessor Nine Months Ended September 30, 2011
Realized gains (losses):				
Commodity derivatives (revenue)	$ 5,808	$ 6,029	$ 17,876	$ 6,070
Interest rate derivatives (other income/expense)	(153)	(141)	(294)	(439)
Unrealized gains (losses):				
Commodity derivatives (revenue)	(21,463)	29,253	(10,455)	26,144
Interest rate derivatives (other income/expense)	(2,124)	134	(4,171)	297

Credit Risk. All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative instruments involves the risk that the counterparties may be unable to meet the financial terms of the transactions. We monitor the creditworthiness of each of our counterparties and assess the possibility of whether each counterparty to the derivative contract would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. We also have netting arrangements in place with each counterparty to reduce credit exposure. The derivative transactions are placed with major financial institutions that we believe present minimal credit risks to us. Additionally, we consider ourselves to be of substantial credit quality and have the financial resources and willingness to meet our potential repayment obligations associated with the derivative transactions.

9. Related Parties

Ownership in Our General Partner by the Management of Fund I and its Affiliates

As of September 30, 2012, Lime Rock Management, an affiliate of Fund I, owned all of the Class A member interests in our general partner. Fund I owned all of the Class B member interests in our general partner and Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. owned all of the Class C member interests in our general partner. In addition, Fund I owned an aggregate of approximately 32.1% of our outstanding common units and all of our subordinated units representing limited partner interests in us. In addition, our general partner owned an approximate 0.1% general partner interest in us, represented by 22,400 general partner units, and all of our incentive distribution rights.

Contracts with our General Partner and its Affiliates

We have entered into agreements with our general partner and its affiliates. Refer to Note 1 in the consolidated/combined financial statements included in our Annual Report on Form 10-K for the year ended

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December 31, 2011 for a description of those agreements. For the three and nine months ended September 30, 2012, we paid Lime Rock Management approximately $0.5 million and $1.2 million, respectively, either directly or indirectly, related to these agreements.

In connection with the management of our business, Lime Rock Resources Operating Company, Inc. (OpCo), an affiliate of our general partner, provides services for invoicing and processing of payments to our vendors. Periodically, OpCo remits cash to us for the net working capital received on our behalf. Changes in the affiliates (payable)/receivable balances during the nine months ended September 30, 2012 are included below (in thousands):

	OpCo	Lime Rock Resources	Total
Balance as of December 31, 2011	$	$ (535)	$ (535)
Expenditures	(51,531)	(11,655)	(63,186)
Cash paid for expenditures	47,939	3,471	51,410
Revenues and other	6,690	8,086	14,776
Balance as of September 30, 2012	$ 3,098	$ (633)	$ 2,465

Distributions of Available Cash to Our General Partner and Affiliates

We will generally make cash distributions to our unitholders and our general partner pro rata. As of September 30, 2012, our general partner and its affiliates held 5,049,600 of our common units, all of our subordinated units and 22,400 general partner units. During the nine months ended September 30, 2012, we paid cash distributions of $0.4750 per outstanding unit, or $1.90 on an annualized basis, to all unitholders as of the respective record dates, which totaled approximately $26.5 million.

We announced our third quarter 2012 distribution on October 15, 2012 as discussed in Note 13.

Contributions to Fund I

The following table presents cash received and payments made to Fund I related to the Transferred Properties for the five months ended May 31, 2012 prior to the acquisition of the net assets on June 1, 2012 (in thousands):

Cash receipts	$ (7,755)
Expenses paid	2,414
Capital expenditures paid	472
Contributions to Fund I	$ (4,869)

Predecessor Related Parties

Each of LRR A, LRR B and LRR C has a management agreement with Lime Rock Management, an affiliated entity, to provide management services for the operation and supervision of their respective funds. The management fee is determined by a formula based on the partners invested capital or the equity capital commitment. During the three and nine months ended September 30, 2011, the predecessor expensed $1.6 million and $4.5 million, respectively, in management fees to Lime Rock Management.

For certain oil and natural gas properties where the predecessor is the operator, the predecessor receives income related to joint interest operations. For the three and nine months ended September 30, 2011, the predecessor received $0.2 million and $0.8 million, respectively, of income, which reduced the management fee paid by the predecessor to Lime Rock Management. All related party transactions are at amounts believed to be commensurate with an arm s-length transaction between parties and are stated at fair market value.

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10. Unitholders Equity

Initial Public Offering

On November 16, 2011, we completed our IPO of 9,408,000 common units representing limited partner interests in the Partnership at a price to the public of $19.00 per common unit, or $17.8125 per common unit after payment of the underwriting discount. Total net proceeds from the sale of common units in our IPO were $167.2 million ($178.8 million less $11.2 million for the underwriting discount and a $0.4 million structuring fee). IPO costs were approximately $4.7 million. We reimbursed Fund I for all costs they paid related to our IPO ($3.2 million). Net proceeds of the offering, along with $155.8 million of borrowings under our $500 million senior secured revolving credit agreement, were utilized to make cash distributions and payments to Fund I of approximately $289.9 million and repay $27.3 million of LRR A s debt that we assumed at closing.

On December 14, 2011, we closed the partial exercise of the underwriters option to purchase additional units, and as a result, issued an additional 1,200,000 common units to the public. We used the net proceeds from the sale of the additional common units of $21.3 million, after deducting underwriting discounts and a structuring fee, to pay additional cash consideration for the properties purchased from Fund I in connection with the IPO and to make additional distributions to Fund I. In connection with our IPO, Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness.

Units Outstanding

As of September 30, 2012, we had 15,708,474 common units, 6,720,000 subordinated units and 22,400 general partner units outstanding. In addition, as of September 30, 2012, Fund I owned 5,049,600 common units and all of our subordinated units, representing a 52.4% limited partner interest in us.

11. Net Income (Loss) Per Limited Partner Unit

The following sets forth the calculation of net income (loss) per limited partner unit for the three and nine months ended September 30, 2012 (in thousands, except per unit amounts):

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Net income (loss)	$ (15,558)	$ 2,761
Net income attributable to predecessor operations		(2,265)
Net income (loss) available to unitholders	(15,558)	496
Less: General partner s approximate 0.1% interest in net income (loss)	16	

Limited partners interest in net income (loss)	$	(15,542)	$	496
Weighted average limited partner units outstanding:				
Common units		15,708		15,706
Subordinated units		6,720		6,720
Total		22,428		22,426
Net income (loss) per limited partner unit (basic and diluted)	$	(0.69)	$	0.02

Our subordinated units and restricted unit awards are considered to be participating securities for purposes of calculating our net income (loss) per limited partner unit, and accordingly, are included in basic computation as such. Net income (loss) per limited partner unit is determined by dividing the net income (loss) available to the common unitholders, after deducting our general partner s approximate 0.1% interest in net income (loss), by weighted average number of common units and subordinated units outstanding as of September 30, 2012. The aggregate number of common units and subordinated units outstanding was 15,708,474 and 6,720,000, respectively, as of September 30, 2012.

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12. Equity-Based Compensation

On November 10, 2011, our general partner adopted a long-term incentive plan (2011 LTIP) for employees, consultants and directors of our general partner and its affiliates, including Lime Rock Management and OpCo, who perform services for us. The 2011 LTIP consists of unit options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, unit awards and other unit-based awards. The 2011 LTIP initially limits the number of units that may be delivered pursuant to vested awards to 1,500,000 common units. As of September 30, 2012, there were 1,449,126 units available for issuance under the 2011 LTIP. The 2011 LTIP is currently administered by our general partner s board of directors.

The fair value of restricted units is determined based on the fair market value of the units on the date of grant. The outstanding restricted units vest over three years in equal amounts (subject to rounding) on the date of grant and are entitled to receive quarterly distributions during the vesting period.

A summary of the status of the non-vested units as of September 30, 2012, is presented below:

	Number of Non-vested Units		Weighted Average Grant-Date Fair Value
Non-vested restricted units at January 1, 2012	42,474	$	18.88
Granted	8,400		20.89
Vested			
Forfeited			
Non-vested restricted units at September 30, 2012	50,874	$	19.21

As of September 30, 2012, there was approximately $0.7 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 2.2 years. There were no vested restricted units as of September 30, 2012.

13. Subsequent Events

On October 15, 2012, we announced that the board of directors of our general partner declared a cash distribution for the third quarter of 2012 of $0.4775 per outstanding unit, or $1.91 on an annualized basis. The distribution will be paid on November 14, 2012 to all unitholders of record as of the close of business on October 30, 2012. The aggregate amount of the distribution will be approximately $10.7 million.

In October 2012, we entered into the following commodity hedges.

	Index	2017
Gas Hedges		
Price swaps (MMBTUs)	NYMEX-HH	2,046,840
Weighted average price		$ 4.71

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

Cautionary Note Regarding Forward-Looking Statements

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 our control, which may include statements about our:

- *business strategies;*
- *ability to replace the reserves we produce through drilling and property acquisitions;*
- *drilling locations;*
- *oil and natural gas reserves;*
- *technology;*
- *realized oil and natural gas prices;*
- *production volumes;*
- *lease operating expenses;*
- *general and administrative expenses;*
- *future operating results;*
- *cash flows and liquidity;*
- *availability of drilling and production equipment;*
- *general economic conditions;*
- *effectiveness of risk management activities; and*
- *plans, objectives, expectations and intentions.*

All statements, other than statements of historical fact, are forward-looking statements. These forward-looking statements can be identified by their use of terms and phrases such as may, predict, pursue, expect, estimate, project, plan, believe, intend, achievable, anti continue, potential, should, could and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking *statements are reasonable, they do involve certain assumptions, risks and uncertainties, some of which are beyond our control. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the risk factors described in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2011 which describe factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:*

- *our ability to generate sufficient cash to pay the minimum quarterly distribution on our common units;*
- *our ability to replace the oil and natural gas reserves we produce;*
- *our substantial future capital expenditures, which may reduce our cash available for distribution and could materially affect our ability to make distributions on our common units;*
- *a decline in, or substantial volatility of, oil, natural gas or NGL prices;*
- *the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production;*
- *the risk that our hedging strategy may be ineffective or may reduce our income;*
- *uncertainty inherent in estimating our reserves;*
- *the risks and uncertainties involved in developing and producing oil and natural gas;*
- *risks related to potential acquisitions, including our ability to make accretive acquisitions on economically acceptable terms or to integrate acquired properties;*
- *competition in the oil and natural gas industry;*
- *cash flows and liquidity;*
- *restrictions and financial covenants contained in the instruments governing our existing indebtedness;*
- *the availability of pipelines, transportation and gathering systems and processing facilities owned by third parties;*
- *electronic, cyber, and physical security breaches;*
- *general economic conditions; and*

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- *legislation and governmental regulations, including climate change legislation and federal or state regulation of hydraulic fracturing.*

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document and speak only as of the date of this report. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Overview

LRR Energy, L.P. (we, us, our, or the Partnership) is a Delaware limited partnership formed in April 2011 by Lime Rock Management LP (Li Rock Management), an affiliate of Lime Rock Resources A, L.P. (LRR A), Lime Rock Resources B, L.P. (LRR B) and Lime Rock Resources C, L.P. (LRR C), to operate, acquire, exploit and develop producing oil and natural gas properties in North America with long-lived, predictable production profiles. LRR A, LRR B and LRR C were formed by Lime Rock Management in July 2005 for the purpose of acquiring mature, low-risk producing oil and natural gas properties with long-lived production profiles. As used herein, references to Fund I or predecessor refer collectively to LRR A, LRR B and LRR C. Fund I is managed by Lime Rock Management and pays a management fee to Lime Rock Management. In addition, Fund I also receives administrative services from, and pays an administrative services fee to, Lime Rock Resources Operating Company, Inc.

Our properties are located in the Permian Basin region in West Texas and southeast New Mexico, the Mid-Continent region in Oklahoma and East Texas and the Gulf Coast region in Texas.

Contribution of Properties

In connection with the completion of our IPO on November 16, 2011, pursuant to a contribution, conveyance and assumption agreement, we acquired specified oil and natural gas properties and related net profits interests and operations and certain commodity derivative contracts (the Partnership Properties) owned by LRR A, LRR B, and LRR C.

Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness. For further discussion regarding our IPO, please see Note 10 to the consolidated/combined condensed financial statements included in this report.

On June 1, 2012, we completed an acquisition from Fund I of certain oil and natural gas properties (the Transferred Properties) located in the Permian Basin region of New Mexico and onshore Gulf Coast region of Texas for $65.1 million in cash consideration (the Transaction). The Transaction was effective as of March 1, 2012. In September 2012, we received $1.1 million in cash from Fund I related to post-closing adjustments to the purchase price for the acquisition.

Results of Operations

Our discussion and analysis of the results of operations below discusses the Partnership s and predecessor s results of operations separately. Because the historical results of our predecessor include results for both the properties conveyed to us in connection with our IPO and properties retained by our predecessor, we do not consider the historical results of our predecessor to be indicative of our future results. Our discussion and analysis below includes a comparison of the three months ended September 30, 2012 to the three months ended June 30, 2012. We believe this comparison will enable the reader to assess material changes in our results of operations in calendar year 2012. We will first compare our results of operations between comparable interim periods beginning with our Quarterly Report on Form 10-Q for the quarter ending March 31, 2013.

Because Fund I and its affiliates own 100% of our general partner and because Fund I owns 5,049,600 common units and all of our 6,720,000 subordinated units, representing an aggregate 52.4% limited partner interest in us, each acquisition of assets from Fund I is considered a transfer of net assets between entities under common control.

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As a result, we are required to revise our financial statements to include the activities of such assets for all periods presented, similar to a pooling of interests, to include the financial position, results of operations and cash flows of the assets acquired and liabilities assumed. The table set forth below includes selected recast historical financial information as if the Transferred Properties were owned by us for all periods presented.

	Partnership			Predecessor	
	Three Months Ended June 30, 2012	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
Revenues (in thousands):					
Oil sales	$ 15,555	$ 16,502	$ 47,415	$ 16,677	$ 51,338
Natural gas sales	4,345	5,691	15,477	9,699	31,453
Natural gas liquids sales	2,713	2,633	8,403	4,508	12,266
Realized gain (loss) on commodity derivative instruments	6,820	5,808	17,876	6,029	6,070
Unrealized gain (loss) on commodity derivative instruments	10,997	(21,463)	(10,455)	29,253	26,144
Other income		30	33	42	122
Total revenues	40,430	9,201	78,749	66,208	127,393
Expenses (in thousands):					
Lease operating expense	6,912	6,919	20,127	6,797	18,732
Production and ad valorem taxes	1,700	1,987	5,348	2,711	5,731
Depletion and depreciation	10,559	8,267	28,126	11,163	32,034
Impairment of oil and natural gas properties		451	3,544	16,765	16,765
Management fees				1,579	4,546
General and administrative expense	3,229	2,294	8,595	1,208	4,414
Interest expense	1,332	2,081	4,541	255	814
Realized loss on interest rate derivative instruments	108	153	294	141	439
Unrealized (gain) loss on interest rate derivative instruments	2,852	2,124	4,171	(134)	(297)
Production:					
Oil (MBbls)	181	192	530	192	563
Natural gas (MMcf)	2,021	2,026	6,098	2,262	7,464
NGLs (MBbls)	70	83	214	83	237