LRR Energy, L.P.
Form 10-Q
August 07, 2013
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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 June 30, 2013

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

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 19,448,539 Common Units, 6,720,000 Subordinated Units and 22,400 General Partner Units outstanding as of August 2, 2013. 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)

	June 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,892	$ 3,467
Accounts receivable	9,818	7,250
Commodity derivative instruments	14,200	16,484
Due from affiliates	3,469	
Prepaid expenses	1,027	748
Total current assets	33,406	27,949
Property and equipment (successful efforts method)	859,554	840,736
Accumulated depletion, depreciation and impairment	(345,005)	(324,774)
Total property and equipment, net	514,549	515,962
Commodity derivative instruments	21,454	20,000
Deferred financing costs, net of accumulated amortization	1,349	1,559
TOTAL ASSETS	$ 570,758	$ 565,470
LIABILITIES AND UNITHOLDERS EQUITY		
Current liabilities:		
Accrued liabilities	$ 4,002	$ 1,415
Accrued capital cost	7,023	2,361
Due to affiliates		1,977
Commodity derivative instruments	1,657	1,671
Interest rate derivative instruments	588	659
Asset retirement obligations	387	500
Total current liabilities	13,657	8,583
Long-term liabilities:		
Commodity derivative instruments	503	874
Interest rate derivative instruments	473	3,526
Term loan	50,000	50,000
Revolving credit facility	192,000	178,000
Asset retirement obligations	34,776	33,591
Deferred tax liabilities	114	120
Total long-term liabilities	277,866	266,111
Total liabilities	291,523	274,694
Unitholders equity:		
Predecessor s capital		60,941
General partner (22,400 units issued and outstanding as of June 30, 2013 and December 31, 2012)	387	396
Public common unitholders (17,598,939 units issued and outstanding as of June 30, 2013 and 10,676,742 units issued and outstanding as of December 31, 2012)	239,689	169,919

Affiliated common unitholders (1,849,600 units issued and outstanding as of June 30, 2013 and 5,049,600 units issued and outstanding as of December 31, 2012)		8,231		25,563
Subordinated unitholders (6,720,000 units issued and outstanding as of June 30, 2013 and December 31, 2012)		30,928		33,957
Total unitholders equity		279,235		290,776
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$	570,758	$	565,470

See accompanying notes to the unaudited consolidated condensed financial statements.

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LRR Energy, L.P.

Consolidated Condensed Statements of Operations

(Unaudited)

(in thousands, except per unit amounts)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Revenues:				
Oil sales	$ 19,012	$ 18,709	$ 34,475	$ 37,188
Natural gas sales	7,720	4,827	13,800	10,810
Natural gas liquids sales	2,275	2,955	4,510	6,186
Realized gain on commodity derivative instruments	2,143	6,820	6,248	12,068
Unrealized gain on commodity derivative instruments	10,211	12,953	39	12,365
Other income	18		87	3
Total revenues	41,379	46,264	59,159	78,620
Operating expenses:				
Lease operating expense	5,270	8,003	12,067	15,071
Production and ad valorem taxes	2,198	1,929	4,044	3,800
Depletion and depreciation	10,129	12,011	20,239	22,627
Impairment of oil and natural gas properties				3,093
Accretion expense	477	390	947	774
Loss (gain) on settlement of asset retirement obligations	360	(10)	335	(108)
General and administrative expense	2,768	3,450	6,197	6,745
Total operating expenses	21,202	25,773	43,829	52,002
Operating income	20,177	20,491	15,330	26,618
Other income (expense), net				
Interest expense	(2,249)	(1,332)	(4,514)	(2,460)
Realized loss on interest rate derivative instruments	(178)	(108)	(352)	(141)
Unrealized gain (loss) on interest rate derivative instruments	2,835	(2,852)	3,124	(2,047)
Other income (expense), net	408	(4,292)	(1,742)	(4,648)
Income before taxes	20,585	16,199	13,588	21,970
Income tax expense	(62)	(24)	(67)	(150)
Net income	$ 20,523	$ 16,175	$ 13,521	$ 21,820
Net income attributable to predecessor operations		(3,970)	(448)	(5,766)
Net income available to unitholders	$ 20,523	$ 12,205	$ 13,073	$ 16,054
Computation of net income per limited partner unit:				
General partners interest in net income	$ 21	$ 12	$ 13	$ 16
Limited partners interest in net income	$ 20,502	$ 12,193	$ 13,060	$ 16,038
Net income per limited partner unit (basic and diluted)	$ 0.78	$ 0.54	$ 0.53	$ 0.72
	26,169	22,428	24,555	22,425

Weighted average number of limited partner units outstanding

See accompanying notes to the unaudited consolidated 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		
	Predecessor s Capital	General Partner	Public Common	Common	Subordinated	Total
Balance, December 31, 2012	$ 60,941	$ 396	$ 169,919	$ 25,563	$ 33,957	$ 290,776
Contribution to Lime Rock Resources	(734)		(445)	337	91	(751)
Book value of transferred properties contributed by Lime Rock Resources	(60,655)					(60,655)
Equity offering, net of expenses			59,513			59,513
Equity offering by limited partners			15,281	(15,281)		
Amortization of equity awards			253			253
Distribution		(22)	(13,617)	(3,316)	(6,467)	(23,422)
Net income	448	13	8,785	928	3,347	13,521
Balance, June 30, 2013	$	$ 387	$ 239,689	$ 8,231	$ 30,928	$ 279,235

See accompanying notes to the unaudited consolidated condensed financial statements.

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LRR Energy, L.P.

Consolidated Condensed Statements of Cash Flows

(Unaudited)

(in thousands)

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 13,521	$ 21,820
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion and depreciation	20,239	22,627
Impairment of oil and natural gas properties		3,093
Unrealized gain on derivative instruments, net	(3,163)	(10,318)
Accretion expense	947	774
Amortization of equity awards	253	150
Amortization of derivative contracts	508	1
Amortization of deferred financing costs and other	187	159
Loss (gain) on settlement of asset retirement obligations	335	(108)
Purchase of derivative contracts		(59)
Changes in operating assets and liabilities:		
Change in receivables	(2,568)	4,472
Change in prepaid expenses	(279)	(84)
Change in accrued liabilities and deferred tax liabilities	2,581	(1,438)
Change in amounts due to/from affiliates	(5,446)	47
Net cash provided by operating activities	27,115	41,136
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of oil and natural gas properties		(8,719)
Development of oil and natural gas properties	(14,375)	(12,607)
Expenditures for other property and equipment		(16)
Net cash used in investing activities	(14,375)	(21,342)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings under revolving credit facility	38,000	67,000
Principal payments on revolving credit facility	(24,000)	(50,000)
Borrowings under term loan		50,000
Equity offering, net of expenses	59,513	
Deferred financing costs		(532)
Distribution to Lime Rock Resources	(60,672)	(65,114)
Contribution to Lime Rock Resources	(734)	(2,128)
Distributions	(23,422)	(15,877)
Net cash used in financing activities	(11,315)	(16,651)
NET INCREASE IN CASH AND CASH EQUIVALENTS	1,425	3,143
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	3,467	1,513
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 4,892	$ 4,656
Supplemental disclosure of non-cash items to reconcile investing and financing activities		

Property and equipment:				
Change in accrued capital costs	$	4,662	$	5,303
Asset retirement obligations		(313)		(81)

See accompanying notes to the unaudited consolidated condensed financial statements.

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LRR Energy, L.P.

Notes to Consolidated 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 refer collectively to LRR A, LRR B and LRR C and references to Fund II refer collectively to Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. References to Lime Rock Resources refer collectively to Fund I and Fund II. 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. We conduct our operations through our wholly owned subsidiary, LRE Operating, LLC (OLLC).

We own 100% of LRE Finance Corporation (LRE Finance). LRE Finance was organized for the purpose of co-issuing our debt securities and has no material assets or liabilities other than as co-issuer of our debt securities, if and when issued. Its activities are limited to co-issuing our debt securities and engaging in activities related thereto.

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, 2012 (2012 Annual Report), and are supplemented by the notes to these unaudited consolidated condensed financial statements. There have been no significant changes to these policies, and these unaudited consolidated condensed financial statements should be read in conjunction with the audited consolidated/combined financial statements and notes in our 2012 Annual Report.

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 financial statements and should be read in conjunction with the audited consolidated/combined financial statements in our 2012 Annual Report. 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 condensed financial statements reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for the periods presented.

The Partnership s 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 acquisitions described in Note 3 and other acquisitions completed in 2012 that we considered to be between entities under common control.

Recent accounting pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-11, Disclosures about Offsetting Assets and Liabilities. ASU No. 2011-11 required entities to disclose both gross information and net information about 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 objective of the disclosure is to facilitate comparison between those entities that prepare their financial statements on the basis of GAAP and those entities that prepare their financial statements on the basis of International Financial Reporting Standards. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which clarified the scope of these disclosures to include

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bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. We adopted this guidance effective January 1, 2013. This guidance did not have a material impact on our consolidated financial position, results of operations or cash flows.

3. Acquisitions

Acquisition between Entities under Common Control

On January 3, 2013, we completed an acquisition from Fund I of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma for a purchase price of $21.0 million, subject to customary purchase price adjustments (the January 2013 Acquisition). In addition, as part of the January 2013 Acquisition, we acquired in the money commodity hedge contracts valued at approximately $1.7 million as of the closing of the January 2013 Acquisition. The January 2013 Acquisition was effective October 1, 2012. In June 2013, we paid $0.4 million in cash to Fund I related to post-closing adjustments to the purchase price. We funded the January 2013 Acquisition with borrowings under our revolving credit facility (Note 7).

The following table presents the net assets conveyed by Fund I to us in the January 2013 Acquisition (in thousands):

Property and equipment, net	$	23,998
Oil and natural gas commodity hedge contracts		1,742
Asset retirement obligations and other liabilities		(1,067)
Net assets	$	24,673

On April 1, 2013, we completed an acquisition of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma and crude oil hedges from Fund II for a purchase price of $38.2 million (the April 2013 Acquisition). As part of the April 2013 Acquisition, we acquired in the money crude oil hedges valued at approximately $0.4 million as of the closing of the April 2013 Acquisition. The April 2013 Acquisition was effective April 1, 2013. We funded the April 2013 Acquisition with proceeds from our equity offering described in Note 10.

The following table presents the net assets conveyed by Fund II to us in the April 2013 Acquisition (in thousands):

Property and equipment, net	$	36,586
Oil and natural gas commodity hedge contracts		386
Asset retirement obligations and other liabilities		(990)
Net assets	$	35,982

The net assets of the January 2013 Acquisition and April 2013 Acquisition were recorded using carryover book value of Fund I and Fund II, respectively, as the acquisitions were deemed transactions between entities under common control. Our historical financial statements were revised to include the results attributable to previous acquisitions from Fund I and Fund II as if we owned the properties for all periods presented in our consolidated condensed financial statements.

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. All such financial instruments are considered Level 1 instruments. The carrying value of our senior secured revolving credit facility and term loan, including the current portion, approximates fair value, as interest rates are variable based on prevailing market rates and are therefore considered Level 1 instruments. Our financial and non-financial assets and liabilities that are measured on a recurring basis are measured and reported at fair value.

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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.

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 (in thousands).

	Level 1	Level 2	Level 3	Total
June 30, 2013				
Assets:				
Commodity derivative instruments	$	$ 35,654	$	$ 35,654
Liabilities:				
Commodity derivative instruments		2,160		2,160
Interest rate derivative instruments		1,061		1,061
December 31, 2012				
Assets:				
Commodity derivative instruments	$	$ 36,484	$	$ 36,484
Liabilities:				
Commodity derivative instruments		2,545		2,545
Interest rate derivative instruments		4,185		4,185

All fair values reflected in the table above and on the 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.

5. Property and Equipment

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

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		June 30, 2013		December 31, 2012
Oil and natural gas properties (successful efforts method)	$	857,983	$	839,154
Unproved properties		1,264		1,264
Other property and equipment		307		318
		859,554		840,736
Accumulated depletion, depreciation and impairment		(345,005)		(324,774)
Total property and equipment, net	$	514,549	$	515,962

We recorded $10.1 million and $12.0 million of depletion and depreciation expense for the three months ended June 30, 2013 and 2012, respectively. We recorded $20.2 million and $22.6 million of depletion and depreciation expense for the six months ended June 30, 2013 and 2012, respectively.

We perform an impairment analysis of our oil and natural gas properties on a quarterly basis due to the volatility in commodity prices. We did not record any impairment charges in the three or six months ended June 30, 2013 or three months ended June 30, 2012. For the six months ended June 30, 2012, we recorded a total non-cash impairment charge of approximately $3.1 million to impair the value of our proved oil and natural gas properties in the Mid-Continent region. This non-cash charge is included in the Impairment of oil and natural gas properties line item in the consolidated condensed statements of operations.

This 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. These reports are based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials. These observable inputs are classified as Level 3 measurements. 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 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 natural gas prices. Significant assumptions in valuing the unproved reserves included the evaluation of the probable and possible reserves included in the reserve reports, future expected oil and natural gas prices and basis differentials, and anticipated drilling schedules.

This asset impairment had no impact on cash flows, liquidity positions, 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 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 asset retirement obligations as of and for the six months ended June 30, 2013 (in thousands):

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Beginning of period	$	34,091
Revisions to previous estimates		
Liabilities incurred		313
Liabilities settled		(188)
Accretion expense		947
End of period		35,163
Less: Current portion of asset retirement obligations		387
Asset retirement obligations non-current	$	34,776

7. Long-Term Debt

Credit Agreement

In July 2011, subject to consummation of our initial public offering, 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 $250 million as of June 30, 2013. Our borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders and once during the interim periods at their sole discretion. As of June 30, 2013, we were in compliance with all covenants contained in the Credit Agreement.

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. As of June 30, 2013, 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 June 30, 2013, we had approximately $242.0 million of outstanding debt and accrued interest was approximately $0.2 million. As of December 31, 2012, we had approximately $228.0 million of outstanding debt and accrued interest was approximately $0.2 million.

Interest expense for the three months ended June 30, 2013 and 2012 was $2.2 million and $1.3 million, respectively. Interest expense for the six months ended June 30, 2013 and 2012 was $4.5 million and $2.5 million, respectively. As of June 30, 2013 and December 31, 2012, our weighted average interest rate on our outstanding indebtedness was 3.62% and 3.47%, 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,

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locational differences between a published index and the NYMEX futures on natural gas or crude oil productions, and interest rate fluctuations.

Our open positions typically consist of contracts such as (i) crude oil and natural gas financial collar contracts, (ii) crude oil, natural gas liquids (NGLs) and natural gas financial swaps, (iii) crude oil and 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 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 consolidated condensed 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 in the consolidated condensed balance sheets.

At June 30, 2013, we had the following open commodity derivative contracts:

	Index	2013	2014	2015	2016	2017
Natural gas positions						
Price swaps (MMBTUs)	NYMEX-HH	3,790,956	6,077,016	5,500,236	5,433,888	5,045,760
Weighted average price		$ 5.09	$ 5.53	$ 5.72	$ 4.29	$ 4.61

Basis swaps (MMBTUs)	NYMEX		3,723,151		5,876,098		5,326,559		2,877,047	
Weighted average price		$	(0.1364)	$	(0.1521)	$	(0.1661)	$	(0.1115)	$
Puts (MMBTUs)	NYMEX-HH		49,260							
Strike price		$	3.00	$		$		$		$

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	Index	2013	2014	2015	2016	2017
Oil positions						
Price swaps (BBLs)	NYMEX-WTI	355,741	580,357	420,381	397,488	198,744
Weighted average price		$ 95.45	$ 95.93	$ 94.72	$ 86.02	$ 85.75
Basis swaps (BBLs)	Argus-	239,780	410,400			
Weighted average price	Midland-Cushing	$ (1.25)	$ (1.00)	$	$	$
NGL positions						
Price swaps (BBLs)	Mont Belvieu	108,450	183,857			
Weighted average price		$ 41.99	$ 34.11	$	$	$

At December 31, 2012, we had the following open commodity derivative contracts:

	Index	2013	2014	2015	2016	2017
Natural gas positions						
Price swaps (MMBTUs)	NYMEX-HH	7,516,540	6,077,016	5,500,236	4,878,990	4,605,396
Weighted average price		$ 5.16	$ 5.53	$ 5.72	$ 4.28	$ 4.61
Basis swaps (MMBTUs)	NYMEX	7,446,301	5,876,098	5,326,559	2,877,047	
Weighted average price		$ (0.1361)	$ (0.1521)	$ (0.1661)	$ (0.1115)	$
Puts (MMBTUs)	NYMEX-HH	178,710				
Strike price		$ 3.00	$	$	$	$
Oil positions						
Price swaps (BBLs)	NYMEX-WTI	698,816	519,102	420,381	397,488	198,744
Weighted average price		$ 95.95	$ 96.61	$ 94.72	$ 86.02	$ 85.75
NGL positions						
Price swaps (BBLs)	Mont Belvieu	144,323				
Weighted average price		$ 50.49	$	$	$	$

At June 30, 2013 and December 31, 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

Effect of Derivative Instruments   Balance Sheet

The fair value of our commodity and interest rate derivative instruments is included in the tables below (in thousands):

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	As of June 30, 2013			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$ 949	$ 588	$ 1,422
Gross fair value		949	588	1,422
Netting arrangements		(949)		(949)
Net recorded fair value	$	$	$ 588	$ 473
Sale of natural gas production				
Price swaps	$ 10,529	$ 13,910	$ 121	$ 641
Basis swaps	40	40	187	364
Sale of crude oil production				
Price swaps	3,087	7,998	1,651	69
Basis swaps			389	125
Sale of NGLs				
Price swaps	1,248	204	13	2
Gross fair value	14,904	22,152	2,361	1,201
Netting arrangements	(704)	(698)	(704)	(698)
Net recorded fair value	$ 14,200	$ 21,454	$ 1,657	$ 503

	As of December 31, 2012			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Interest rate				
Swaps	$	$ 13	$ 659	$ 3,539
Gross fair value		13	659	3,539
Netting arrangements		(13)		(13)
Net recorded fair value	$	$	$ 659	$ 3,526
Sale of natural gas production				
Price swaps	$ 12,185	$ 17,460	$ 155	$ 1,073
Basis swaps	18	27	317	470
Sale of crude oil production				
Price swaps	3,949	5,248	2,061	2,066
Sale of NGLs				
Price swaps	1,209		15	
Gross fair value	17,361	22,735	2,548	3,609
Netting arrangements	(877)	(2,735)	(877)	(2,735)
Net recorded fair value	$ 16,484	$ 20,000	$ 1,671	$ 874

Effect of Derivative Instruments Statement of Operations

The unrealized and realized gain or loss amounts and classification related to derivative instruments are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Realized gains (losses):				
Commodity derivatives (revenue)	$ 2,143	$ 6,820	$ 6,248	$ 12,068
Interest rate derivatives (other income/expense)	(178)	(108)	(352)	(141)

Unrealized gains (losses):				
Commodity derivatives (revenue)	10,211	12,953	39	12,365
Interest rate derivatives (other income/expense)	2,835	(2,852)	3,124	(2,047)

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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 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 of our General Partner by Lime Rock Management and its Affiliates

As of June 30, 2013, 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 Fund II owned all of the Class C member interests in our general partner. In addition, Fund I owned an aggregate of approximately 9.5% of our outstanding common units and all of our subordinated units, representing a 32.7% limited partner interest in us. As of June 30, 2013, 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.

As more fully described in our 2012 Annual Report, three separate one-third tranches of the subordinated units may convert on the first business day after the distribution to unitholders in respect of any quarter ending on or after December 31, 2012, December 31, 2013 and December 31, 2014, respectively, provided that an aggregate amount equal to the minimum quarterly distribution payable with respect to all units that would be payable on four, eight or twelve consecutive quarters, as applicable, has been earned and paid prior to the applicable date, in each case provided there are no arrearages in the minimum quarterly distribution on our common units at that time. We do not expect one third of the subordinated units to convert pursuant to the provisions of our partnership agreement following our distribution for the second quarter of 2013 that will be paid on August 14, 2013. Each quarter, we will determine whether the test for conversion of the subordinated units has been met until the subordinated units convert pursuant to the provisions of our partnership agreement.

Contracts with our General Partner and its Affiliates

We have entered into various agreements with our general partner and its affiliates. For the three months ended June 30, 2013 and 2012, we paid Lime Rock Management approximately \$0.2 million and \$0.5 million, respectively, either directly or indirectly, related to these agreements. For the six months ended June 30, 2013 and 2012, we paid Lime Rock Management approximately \$0.5 million and \$0.7 million, respectively, either directly or indirectly, related to these agreements.

In connection with the management of our business, Lime Rock Resources Operating Company, Inc. (ServCo), an affiliate of our general partner, provides services for invoicing and processing of payments to our vendors. Periodically, ServCo remits cash to us for the net working capital received on our behalf. Changes in the affiliates (payable)/receivable balances during the six months ended June 30, 2013 are included below (in thousands):

	ServCo	Lime Rock Resources	Total
Balance as of December 31, 2012	$ (2,229)	$ 252	$ (1,977)
Expenditures	(41,293)	(790)	(42,083)
Cash paid for expenditures	43,744	96	43,840
Revenues and other	3,934	(245)	3,689
Balance as of June 30, 2013	$ 4,156	$ (687)	$ 3,469

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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 June 30, 2013, our general partner and its affiliates held 1,849,600 of our common units, all of our subordinated units and 22,400 general partner units. During the six months ended June 30, 2013 and 2012, we paid cash distributions of $23.4 million and $15.9 million, respectively, to all unitholders as of the respective record dates.

We announced our second quarter 2013 distribution on July 19, 2013 as discussed in Note 14.

10. Unitholders Equity

Equity Offering

On March 22, 2013, we closed a public equity offering of 3,700,000 common units representing limited partner interests in the Partnership at a price to the public of $16.84 per common unit, or $16.1664 per common unit after payment of the underwriting discount. We received net proceeds from the sale of 3,700,000 newly issued common units of approximately $59.5 million, after deducting underwriting discounts and commissions and offering expenses of approximately $0.3 million. We used the net proceeds of the offering to fund our April 2013 Acquisition discussed in Note 3 and repay borrowings outstanding on our Credit Agreement.

Fund I sold 3,200,000 common units in the equity offering at a price to the public of $16.84 per common unit, or $16.1664 per common unit after payment of the underwriting discount. We did not receive any proceeds from the sale of common units by Fund I; however, the equity balance of Fund I was adjusted for its reduced ownership interest in us.

Units Outstanding

As of June 30, 2013, we had 19,448,539 common units, 6,720,000 subordinated units and 22,400 general partner units outstanding. As of June 30, 2013, Fund I owned 1,849,600 common units and all of our subordinated units, representing a 32.7% limited partner interest in us.

11. Net Income Per Limited Partner Unit

The following sets forth the calculation of net income per limited partner unit (in thousands, except per unit amounts):

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net income	$ 20,523	$ 16,175	$ 13,521	$ 21,820
Net income attributable to predecessor operations		(3,970)	(448)	(5,766)
Net income available to unitholders	20,523	12,205	13,073	16,054
Less: General partner s approximate 0.1% interest in net income	(21)	(12)	(13)	(16)
Limited partners interest in net income	$ 20,502	$ 12,193	$ 13,060	$ 16,038
Weighted average limited partner units outstanding:				
Common units	19,449	15,708	17,835	15,705
Subordinated units	6,720	6,720	6,720	6,720
Total	26,169	22,428	24,555	22,425
Net income per limited partner unit (basic and diluted)	$ 0.78	$ 0.54	$ 0.53	$ 0.72

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Our subordinated units and restricted unit awards are considered to be participating securities for purposes of calculating our net income per limited partner unit, and accordingly, are included in basic computation as such. Net income per limited partner unit is determined by dividing the net income available to the common unitholders, after deducting our general partner s approximate 0.1% interest in net income, by weighted average number of common units and subordinated units outstanding as of June 30, 2013 and 2012. The aggregate number of common units and subordinated units outstanding was 19,448,539 and 6,720,000, respectively, as of June 30, 2013. The aggregate number of common units and subordinated units outstanding was 15,708,474 and 6,720,000, respectively, as of June 30, 2012.

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 ServCo, 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 June 30, 2013, there were 1,409,061 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 June 30, 2013, is presented below:

	Number of Non-vested Units	Weighted Average Grant-Date Fair Value
Non-vested restricted units at December 31, 2012	54,584	
Granted	22,197	$ 17.12
Vested	(2,800)	20.89
Forfeited		
Non-vested units at June 30, 2013	73,981	

As of June 30, 2013, there was approximately $1.1 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 2.1 years. There were 16,958 vested restricted units as of June 30, 2013.

13. Subsidiary Guarantors

We and LRE Finance, our 100 percent-owned subsidiary, filed a registration statement on Form S-3 with the SEC on December 10, 2012, and the SEC declared the registration statement effective on January 16, 2013. Securities that may be offered and sold include debt securities that are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933. LRE Finance may co-issue any debt securities issued by us pursuant to the registration statement. LRE Finance was formed solely for the purpose of co-issuing our debt securities and has no material assets or liabilities other than as co-issuer of our debt securities. OLLC, our 100 percent-owned subsidiary, may guarantee any debt securities issued by us and such guarantee will be full and unconditional, subject to customary release provisions. The guarantee will be released (i) automatically upon any sale, exchange or transfer of our equity interests in OLLC, (ii) automatically upon the liquidation and dissolution of OLLC, (iii) following delivery of notice to the trustee under the indenture related to the debt securities of the release of OLLC of its obligations under the Partnership s revolving credit facility, and (iv) upon legal or covenant defeasance or other satisfaction of the obligations under the related debt securities. Other than LRE Finance, OLLC is our sole subsidiary, and thus, no other subsidiary will guarantee our debt securities.

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Furthermore, we have no assets or operations independent of OLLC, and there are no significant restrictions upon the ability of OLLC to distribute funds to us by dividend or loan. Finally, none of our assets or OLLC represents restricted net assets pursuant to Rule 4-08(e)(3) of Regulation S-X.

14. Subsequent Events

Unit Distribution

On July 19, 2013, we announced that the board of directors of our general partner declared a cash distribution for the second quarter of 2013 of $0.485 per outstanding unit, or $1.94 on an annualized basis. The distribution will be paid on August 14, 2013 to all unitholders of record as of the close of business on July 30, 2013. The aggregate amount of the distribution will be approximately $12.7 million.

Commodity Hedges

Subsequent to June 30, 2013, we acquired the following commodity hedges:

	Index	2013	2014
Oil positions			
Price swaps (BBLs)	NYMEX-WTI	17,100	93,637
Weighted average price		$ 101.61	$ 95.35

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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, 2012 that 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 oil, natural gas or natural gas liquids (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 in our credit facility and term loan;*
- *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 refer collectively to LRR A, LRR B and LRR C. Fund I is managed by Lime Rock Management and references to Fund II refer collectively to Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. References to Lime Rock Resources refer collectively to Fund I and Fund II.

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

On January 3, 2013, we completed an acquisition from Fund I of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma for a purchase price of $21.0 million, subject to customary purchase price adjustments (the January 2013 Acquisition). In addition, as part of the January 2013 Acquisition, we acquired in the money commodity hedge contracts valued at approximately $1.7 million at the closing of the January 2013 Acquisition. The January 2013 Acquisition was effective October 1, 2012. In June 2013, we paid $0.4 million in cash to Fund I related to post-closing adjustments to the purchase price.

On April 1, 2013, we completed an acquisition of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma and crude oil hedges from Fund II for a purchase price of $38.2 million (the April 2013 Acquisition). As part of the April 2013 Acquisition, we acquired in the money crude oil hedges valued at approximately $0.4 million as of the closing of the April 2013 Acquisition. The April 2013 Acquisition was effective April 1, 2013. We funded the April 2013 Acquisition with proceeds from our equity offering described in Note 10 to the consolidated condensed financial statements included in this report.

Results of Operations

The January 2013 Acquisition and April 2013 Acquisition were deemed to be transactions between entities under common control. As a result, our financial statements were revised 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. Please refer to Note 2 of our Annual Report on Form 10-K for the year ended December 31, 2012 (the 2012 Annual Report) regarding the recast of financial information for transactions between entities under common control. The table set forth below includes recast historical financial and operating information attributable to previous acquisitions from Fund I and Fund II as if we owned the properties since November 16, 2011.

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	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Revenues (in thousands):				
Oil sales	$ 19,012	$ 18,709	$ 34,475	$ 37,188
Natural gas sales	7,720	4,827	13,800	10,810
Natural gas liquids sales	2,275	2,955	4,510	6,186
Realized gain on commodity derivative instruments	2,143	6,820	6,248	12,068
Unrealized gain on commodity Derivative instruments	10,211	12,953	39	12,365
Other income	18		87	3
Total revenues	41,379	46,264	59,159	78,620
Expenses (in thousands):				
Lease operating expense	5,270	8,003	12,067	15,071
Production and ad valorem taxes	2,198	1,929	4,044	3,800
Depletion and depreciation	10,129	12,011	20,239	22,627
Impairment of oil and natural gas properties				3,093
General and administrative expense	2,768	3,450	6,197	6,745
Interest expense	2,249	1,332	4,514	2,460
Realized loss on interest rate derivative instruments	178	108	352	141
Unrealized (gain) loss on interest rate derivative instruments	(2,835)	2,852	(3,124)	2,047
Production:				
Oil (MBbls)	210	218	398	407
Natural gas (MMcf)	1,843	2,161	3,651	4,347
NGLs (MBbls)	73	76	145	143
Total (MBoe)	590	654	1,152	1,275
Average net production (Boe/d)	6,484	7,187	6,365	7,005
Average sales price:				
Oil (per Bbl)				
Sales price	$ 90.53	$ 85.82	$ 86.62	$ 91.37
Effect of realized commodity derivative instruments	0.39	5.12	0.80	2.64
Realized price	$ 90.92	$ 90.94	$ 87.42	$ 94.01
Natural gas (per Mcf)				
Sales price	$ 4.19	$ 2.23	$ 3.78	$ 2.49
Effect of realized commodity derivative instruments	0.87	2.42	1.41	2.42
Realized price	$ 5.06	$ 4.65	$ 5.19	$ 4.91
NGLs (per Bbl)				
Sales price	$ 31.16	$ 38.88	$ 31.10	$ 43.26
Effect of realized commodity derivative instruments	6.26	6.33	5.49	3.41
Realized price	$ 37.42	$ 45.21	$ 36.59	$ 46.67
Average unit cost per Boe:				
Lease operating expenses	$ 8.93	$ 12.23	$ 10.48	$ 11.83
Production and ad valorem taxes	3.72	2.95	3.51	2.98
Depletion and depreciation	17.16	18.36	17.58	17.75
General and administrative expenses	4.69	5.27	5.38	5.29

Our Results for the Three Months Ended June 30, 2013 Compared to the Three Months Ended June 30, 2012

We recorded net income of $20.5 million for the three months ended June 30, 2013 compared to net income of $16.2 million during the three months ended June 30, 2012, primarily related to higher sales revenues due to higher commodity prices and lower operating expense. The following discussion summarizes key components of the changes between periods.

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Sales Revenues. A summary of increases (decreases) in our oil, natural gas and NGL revenues between June 30, 2012 and June 30, 2013 follows (in thousands):

Oil, natural gas and NGL revenues-prior period	$	26,491
Increase (decrease)		
Price realization		
Oil		1,027
Natural gas		4,225
NGLs		(587)
Sales volumes		
Oil		(724)
Natural gas		(1,332)
NGLs		(93)
Oil, natural gas and NGL revenues-current period	$	29,007

Sales revenues increased from $26.5 million for the three months ended June 30, 2012 to $29.0 million for the three months ended June 30, 2013, primarily due to higher natural gas and oil price realizations offset by lower natural gas sales volumes. Sales revenues for the three months ended June 30, 2013 consisted of oil sales of $19.0 million, natural gas sales of $7.7 million and NGL sales of $2.3 million. Sales revenues for the three months ended June 30, 2012 consisted of oil sales of $18.7 million, natural gas sales of $4.8 million and NGL sales of $3.0 million.

Our production volumes for the three months ended June 30, 2013 included 283 MBbls of oil and NGLs and 1,843 MMcf of natural gas, or 3,110 Bbl/d of oil and NGLs and 20,253 Mcf/d of natural gas. On an equivalent basis, production for the period was 590 MBoe, or 6,484 Boe/d. Our production volumes for the three months ended June 30, 2012 included 294 MBbls of oil and NGLs and 2,161 MMcf of natural gas, or 3,231 Bbl/d of oil and NGLs and 23,747 Mcf/d of natural gas. On an equivalent basis, production for the period was 654 MBoe, or 7,187 Boe/d.

At our Red Lake field, our third party gas processor required us to flare approximately 90 Boe/d due to third-party compression limits during the quarter. We are currently flaring approximately 90 Boe/d and we expect that we will continue to flare at this level until a new compressor station at the plant is put into service, which we expect will occur during the fourth quarter of 2013.

Our Pecos Slope field continued to be curtailed by approximately 1.0 MMcf/d (167 Boe/d) during the quarter due the previously disclosed high nitrogen content of our produced natural gas. We expect the curtailment to remain at this level until the field-wide nitrogen rejection facility is installed, which we expect will occur in late 2013.

Our average sales price per Bbl for oil and NGLs for the three months ended June 30, 2013, excluding the effect of commodity derivative contracts, was $90.53 and $31.16, respectively. Our average sales price per Mcf of natural gas for the three months ended June 30, 2013, excluding the effect of commodity derivative contracts, was $4.19. Our average sales price per Bbl for oil and NGLs for the three months ended June 30, 2012, excluding the effect of commodity derivative contracts, was $85.82 and $38.88, respectively. Our average sales price per Mcf of natural gas for the three months ended June 30, 2012, excluding the effect of commodity derivative contracts, was $2.23.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, we recorded a net gain from our commodity hedging program for the three months ended June 30, 2013 of approximately $12.3 million, which is comprised of a realized gain of approximately $2.1 million and an unrealized gain of approximately $10.2 million. For the three months ended June 30, 2012, we recorded a net gain from our commodity hedging program of approximately $19.8 million, which is comprised of a realized gain of approximately $6.8 million and an unrealized gain of approximately $13.0 million. Volatility in commodity prices has had a significant impact on our realized and unrealized gains and losses on commodity derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately $5.3 million, or $8.93 per Boe, for the three months ended June 30, 2013 compared to approximately $8.0 million, or $12.23 per Boe, for the three months ended June 30, 2012. The primary drivers of the decreased lease operating expenses were lower workover expenses and lower saltwater disposal costs.

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Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $2.2 million, or $3.72 per Boe, for the three months ended June 30, 2013 compared to approximately $1.9 million, or $2.95 per Boe, for the three months ended June 30, 2012. Production taxes accounted for approximately $2.0 million and ad valorem taxes for $0.2 million of the total taxes recorded during the three months ended June 30, 2013. Production taxes accounted for approximately $1.7 million and ad valorem taxes for $0.2 million of the total taxes recorded during the three months ended June 30, 2012. The increase in the per Boe amounts were primarily related to lower production volumes.

Depletion and Depreciation. Our depletion and depreciation expense was approximately $10.1 million, or $17.16 per Boe, for the three months ended June 30, 2013 compared to approximately $12.0 million, or $18.36 per Boe, for the three months ended June 30, 2012. The decrease in the depreciation expense and per Boe amounts were primarily related to lower production volumes.

Impairment of Oil and Natural Gas Properties. We did not record an impairment charge in the three months ended June 30, 2013 and 2012. If future oil or natural gas prices decline, the estimated undiscounted future cash flows for our proved oil and natural gas properties may not exceed the net capitalized costs for such properties and a non-cash impairment charge may be required to be recognized in future periods. As of August 2, 2013, the NYMEX-WTI oil spot price was $106.94 per Bbl and the NYMEX-Henry Hub natural gas spot price was $3.39 per MMBtu.

General and Administration Expenses. Our general and administrative expenses were approximately $2.8 million, or $4.69 per Boe, for the three months ended June 30, 2013 compared to approximately $3.5 million, or $5.27 per Boe, for the three months ended June 30, 2012. The decrease in general and administrative expenses was primarily due to costs incurred in connection with a drop-down transaction in the second quarter of 2012.

Interest Expenses. Our interest expense is comprised of interest on our credit facility and term loan, amortization of debt issuance costs and realized gains (losses) on our interest rate derivative instruments. Interest expense was approximately $2.4 million and $1.4 million for the three months ended June 30, 2013 and 2012, respectively. The increase in interest expense was primarily due to the increased debt level outstanding during the three months ended June 30, 2013. Unrealized gain on interest rate derivative contracts was approximately $2.8 million for the three months ended June 30, 2013, and unrealized loss on interest rate derivative contracts was approximately $2.9 million for the three months ended June 30, 2012.

Our Results for the Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012

We recorded net income of $13.5 million for the six months ended June 30, 2013 compared to net income of $21.8 million during the six months ended June 30, 2012, primarily related to lower overall revenues and expenses. The following discussion summarizes key components of the changes between periods.

Sales Revenues. A summary of increases (decreases) in our oil, natural gas and NGL revenues between the six months ended June 30, 2012 and June 30, 2013 follows (in thousands):

Oil, natural gas and NGL revenues-prior period	$	54,184
Increase (decrease)		
Price realization		
Oil		(1,933)
Natural gas		5,622
NGLs		(1,739)
Sales volumes		
Oil		(780)
Natural gas		(2,631)
NGLs		62
Oil, natural gas and NGL revenues-current period	$	52,785

Sales revenues decreased from $54.2 million for the six months ended June 30, 2012 to $52.8 million for the six months ended June 30, 2013, primarily driven by lower oil and NGL price realizations and decreased oil and natural

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gas production offset by higher natural gas price realizations. Sales revenues for the six months ended June 30, 2013 consisted of oil sales of $34.5 million, natural gas sales of $13.8 million and NGL sales of $4.5 million. Sales revenues for the six months ended June 30, 2012 consisted of oil sales of $37.2 million, natural gas sales of $10.8 million and NGL sales of $6.2 million.

Our production volumes for the six months ended June 30, 2013 included 543 MBbls of oil and NGLs and 3,651 MMcf of natural gas, or 3,000 Bbl/d of oil and NGLs and 20,171 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,152 MBoe, or 6,365 Boe/d. Our production volumes for the six months ended June 30, 2012 included 550 MBbls of oil and NGLs and 4,347 MMcf of natural gas, or 3,022 Bbl/d of oil and NGLs and 23,885 Mcf/d of natural gas. On an equivalent basis, production for the period was 1,275 MBoe, or 7,005 Boe/d.

Our average daily production of 6,365 Boe/d for the six months ended June 30, 2013 was negatively impacted by the following items which resulted in lower production of approximately 380 Boe/d. The actual timing and amount of resumed production related to the items below may differ from these estimates.

At our Red Lake field, our third party gas processor required us to flare approximately 80 Boe/d due to plant capacity constraints and compressor issues during the six months ended June 30, 2013. We are currently flaring approximately 90 Boe/d due to third-party plant compression limits and we expect that we will continue to flare at this level until a new compressor station at the plant is put into service, which we expect will occur during the fourth quarter of 2013. Delays in our recompletion program at our Red Lake field during the first quarter resulted in lower production of approximately 21 Boe/d. The delayed projects were completed during the second quarter of 2013.

Production at our Putnam field experienced weather related shut-ins of approximately 33 Boe/d during the first quarter of 2013. The Putnam field resumed normal operations in the second quarter of 2013.

Our Pecos Slope field was curtailed by approximately 1.4 MMcf/d (233 Boe/d) during the six months ended June 30, 2013 due to the previously disclosed high nitrogen content of our produced natural gas (1.0 MMcf/d or 167 Boe/d) and a compressor failure (0.4 MMcf/d or 66 Boe/d). The compressor resumed service on February 18, 2013. The current nitrogen content curtailment is approximately 1.0 MMcf/d (167 Boe/d) and we expect it to remain at this level until the field-wide nitrogen rejection facility is installed, which we expect will occur in late 2013. A well at our New Years Ridge field had a tubing failure during the first quarter of 2013 resulting in curtailed production of approximately 75 Mcfe/d (12 Boe/d) during the six months ended June 30, 2013. The well resumed service during the second quarter of 2013.

Our average sales price per Bbl for oil and NGLs for the six months ended June 30, 2013, excluding the effect of commodity derivative contracts, was $86.62 and $31.10, respectively. Our average sales price per Mcf of natural gas for the six months ended June 30, 2013, excluding the effect of commodity derivative contracts, was $3.78. Our average sales price per Bbl for oil and NGLs for the six months ended June 30, 2012, excluding the effect of commodity derivative contracts, was $91.37 and $43.26, respectively. Our average sales price per Mcf of natural gas for the six months ended June 30, 2012, excluding the effect of commodity derivative contracts, was $2.49.

In addition to lower realized production, our financial results for the six months ended June 30, 2013 were impacted by a higher Midland to Cushing oil differential during the first quarter of 2013. The differential averaged $7.88 per barrel for the first quarter compared to the full year 2011 and 2012 average differential of $2.30 per barrel. We estimated the impact of the higher differential (compared to the 2011 and 2012 average differential) on revenue for the first quarter of 2013 was approximately $0.8 million. In February 2013, we executed Midland to Cushing oil basis swaps for March 2013 through December 2014 on the majority of our expected production that we expected to be impacted by the differential.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, we recorded a net gain from our commodity hedging program for the six months ended June 30, 2013 of approximately $6.3 million, which is comprised of a realized gain of approximately $6.3 million and an unrealized gain of less than $0.1 million. For the six months ended June 30, 2012, we recorded a net gain from our commodity hedging program of approximately $24.4 million, which is comprised of a realized gain of approximately $12.1 million and an unrealized gain of approximately $12.3 million. Volatility in commodity prices has had a significant impact on our realized and unrealized gains and losses on commodity derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately $12.1 million, or $10.48 per Boe, for the six months ended June 30, 2013 compared to approximately $15.1 million, or $11.83 per Boe, for the six months ended June 30, 2012. The primary drivers of the decreased lease operating expenses were lower workover expenses and lower saltwater disposal costs.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $4.0 million, or $3.51 per Boe, for the six months ended June 30, 2013 compared to approximately $3.8 million, or $2.98 per Boe, for the six months ended June 30, 2012. Production taxes accounted for approximately $3.6 million and ad valorem taxes for $0.4 million of the total taxes recorded during the six months ended June 30, 2013. Production taxes accounted for approximately $3.5 million and ad valorem taxes for $0.3 million of the total taxes recorded during the six months ended June 30, 2012.

Depletion and Depreciation. Our depletion and depreciation expense was approximately $20.2 million, or $17.58 per Boe, for the six months ended June 30, 2013 compared to approximately $22.6 million, or $17.75 per Boe, for the six months ended June 30, 2012.

Impairment of Oil and Natural Gas Properties. We did not record an impairment charge in the six months ended June 30, 2013. We recorded an impairment of approximately $3.1 million for the six months ended June 30, 2012 on our proved properties during the period. If future oil or natural gas prices decline, the estimated undiscounted future cash flows for our proved oil and natural gas properties may not exceed the net capitalized costs for such properties and a non-cash impairment charge may be required to be recognized in future periods. As of August 2, 2013, the NYMEX-WTI oil spot price was $106.94 per Bbl and the NYMEX-Henry Hub natural gas spot price was $3.39 per MMBtu.

General and Administration Expenses. Our general and administrative expenses were approximately $6.2 million, or $5.38 per Boe, for the six months ended June 30, 2013 compared to approximately $6.7 million, or $5.29 per Boe, for the six months ended June 30, 2012.

Interest Expenses. Our interest expense is comprised of interest on our credit facility and term loan, amortization of debt issuance costs and realized gains (losses) on our interest rate derivative instruments. Interest expense was approximately $4.9 million and $2.6 million for the six months ended June 30, 2013 and 2012, respectively. The increase in interest expense was primarily due to the increased debt level outstanding during the six months ended June 30, 2013. Unrealized gain on interest rate derivative contracts was approximately $3.1 million for the six months ended June 30, 2013, and unrealized loss on interest rate derivative contracts was approximately $2.0 million for the six months ended June 30, 2012.

Non-GAAP Financial Measures

Below we disclose the non-GAAP financial measures Adjusted EBITDA and Distributable Cash Flow for the periods presented and provide reconciliations of these items to net income, our most directly comparable financial performance measure calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income:

- *Plus*:

- Income tax expense (benefit);
- Interest expense-net, including realized and unrealized losses on interest rate derivative contracts;
- Depletion and depreciation;
- Accretion of asset retirement obligations;
- Amortization of equity awards;
- Gain (loss) on settlement of asset retirement obligations;
- Unrealized losses on commodity derivative contracts;
- Amortization of derivative contracts;
- Impairment of oil and natural gas properties; and
- Other non-recurring items that we deem appropriate.

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- *Less*:

- Interest income;
- Unrealized gains on commodity derivative contracts; and
- Other non-recurring items that we deem appropriate.

We define Distributable Cash Flow as Adjusted EBITDA less income tax expense, cash interest expense and estimated maintenance capital expenditures.

Adjusted EBITDA and Distributable Cash Flow are used as supplemental financial measures by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess:

- our operating performance as compared to that of other companies and partnerships in our industry, without regard to financing methods, capital structure or historical cost basis; and
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders.

Our management believes that both Adjusted EBITDA and Distributable Cash Flow are useful to investors because these measures are used by many partnerships in the industry as measures of operating and financial performance and are commonly employed by financial analysts and others to evaluate the operating and financial performance of the Partnership from period to period and to compare it with the performance of other publicly traded partnerships within the industry. Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income, operating income, or any other measures of financial performance presented in accordance with GAAP. Our Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA and Distributable Cash Flow in the same manner.

Our Adjusted EBITDA for the three months ended June 30, 2013 and 2012 was approximately $21.3 million and $20.0 million, respectively. Our Adjusted EBITDA for the six months ended June 30, 2013 and 2012 was approximately $37.6 million and $40.8 million, respectively.

Our Distributable Cash Flow for the three months ended June 30, 2013 and 2012 was approximately $14.1 million and $13.8 million, respectively. Our Distributable Cash Flow for the six months ended June 30, 2013 and 2012 was approximately $23.1 million and $28.0 million, respectively.

Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Income

The following table presents a reconciliation of Adjusted EBITDA and Distributable Cash Flow to net income, our most directly comparable GAAP financial performance measure, for each of the periods indicated.

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(in thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net income	$ 20,523	$ 16,175	$ 13,521	$ 21,820
Income tax expense	62	24	67	150
Interest expense-net, including realized and unrealized losses on interest rate derivative instruments	(408)	4,292	1,742	4,648
Depletion and depreciation	10,129	12,011	20,239	22,627
Accretion of asset retirement obligations	477	390	947	774
Amortization of equity awards	138	81	253	150
Loss (gain) on settlement of asset retirement obligations	360	(10)	335	(108)
Unrealized losses on commodity derivative instruments				
Amortization of derivative contracts	261	1	508	1
Impairment of oil and natural gas properties				3,093
Interest income				
Unrealized gain on commodity derivative instruments	(10,211)	(12,953)	(39)	(12,365)
Adjusted EBITDA	$ 21,331	$ 20,011	$ 37,573	$ 40,790
Adjusted EBITDA	21,331	20,011	37,753	40,790
Income tax expense	(62)	(24)	(67)	(150)
Cash interest expense	(2,135)	(1,080)	(4,264)	(2,490)
Estimated maintenance capital (1)	(5,075)	(5,075)	(10,150)	(10,150)
Distributable Cash Flow	$ 14,059	$ 13,832	$ 23,092	$ 28,000

(1) Amount represents pro-rated capital for the period.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements depends on our ability to generate cash. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for oil and natural gas, weather and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

Our primary sources of liquidity and capital resources are cash flows generated by operating activities, borrowings under our credit facility and term loan and equity offerings. We may issue additional equity and debt as needed.

We enter into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 65% to 85% of our estimated production from total proved developed producing reserves over a three-to-five year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to our unitholders and our general partner. In making cash distributions, our general partner attempts to avoid large variations in the amount we distribute from quarter to quarter. In order to facilitate this, our partnership agreement permits our general partner to establish cash reserves to be used to pay distributions for any one or more of the next four quarters. In addition, our partnership agreement allows our general partner to borrow funds to make distributions.

We may borrow to make distributions to our unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long-term, but short-term factors have caused available cash from operations to be insufficient to sustain our level of distributions. In addition, a significant portion of our production

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is hedged. We are generally required to settle our commodity hedge derivatives within five days of the end of the month. As is typical in the oil and gas industry, we generally do not receive the proceeds from the sale of our hedged production until 45 to 60 days following the end of the month. As a result, when commodity prices increase above the fixed price in the derivative contracts, we are required to pay the derivative counterparty the difference between the fixed price in the derivative contract and the market price before we receive the proceeds from the sale of the hedged production. If this occurs, we may make working capital borrowings to fund our distributions. Because we distribute all of our available cash, we will not have those amounts available to reinvest in our business to increase our proved reserves and production and as a result, we may not grow as quickly as other oil and gas entities or at all.

We are committed to reinvesting a sufficient amount of our cash flow to fund our exploitation and development capital expenditures in order to maintain our production, and we use, and intend to use in the future, primarily external financing sources, including commercial bank borrowings and the issuance of debt and equity interests, rather than cash reserves established by our general partner, to make acquisitions to further increase our production and proved reserves. Because our proved reserves and production decline continually over time and because we do not own any significant undeveloped properties or leasehold acreage, we will need to make acquisitions to sustain our level of distributions to unitholders over time.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures, reduce distributions to unitholders, and/or fund a portion of our capital expenditures using borrowings under our credit facility or term loan, issuances of debt and equity securities or from other sources, such as asset sales. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our credit facility and term loan. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

As of June 30, 2013, we had borrowing capacity of $58.0 million under our $500 million revolving credit facility ($250 million borrowing base less $192.0 million of outstanding borrowings) and $4.9 million of cash on hand. As of June 30, 2013, we had no available borrowing capacity under our $50 million term loan.

Based upon current oil and natural gas price expectations and our commodity derivatives positions for the period ended June 30, 2013, which cover 84% of our remaining 2013 estimated production from total proved developed producing reserves, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient working capital to meet our planned 2013 capital expenditure and minimum distribution requirements as described under Outlook below.

Credit Agreement

In July 2011, subject to consummation of our initial public offering, we, as guarantor, and our wholly owned subsidiary, LRE Operating, LLC (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 $250 million as of June 30, 2013. Our borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders and once during the interim periods at their sole discretion.

A future decline in commodity prices could result in a redetermination that lowers our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base, or we could be required to pledge other oil and natural gas properties as additional collateral. We do not anticipate having any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our credit facility. Additionally, we will not be able to pay distributions to our unitholders in any such quarter in the event there exists a borrowing base deficiency or an event of default either before or after giving effect to such distribution or we are not in pro forma compliance with the credit facility after giving effect to such distribution.

If we fail to perform our obligations under the covenants described in our 2012 Annual Report, the revolving credit commitments could be terminated and any outstanding indebtedness under the credit facility, together with

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accrued interest, could be declared immediately due and payable. As of June 30, 2013, we were in compliance with our covenants.

At June 30, 2013, we had approximately $192.0 million of outstanding borrowings under our credit facility and available borrowing capacity of approximately $58.0 million.

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.

Our Term Loan Agreement contains various covenants and restrictive provisions as described in our 2012 Annual Report. As of June 30, 2013, we were in compliance with all covenants contained in the Term Loan Agreement.

Commodity Derivative Contracts

The following table summarizes, for the periods presented, the weighted average price and notional volumes of our oil, NGL and natural gas swaps and collars in place as of June 30, 2013. The weighted average price is based on the swap price for oil, NGL and natural gas swaps and the floor price of oil and natural gas collars. We use swaps and collars as a mechanism for managing commodity price risks whereby we pay the counterparty floating prices and receive fixed prices from the counterparty. By entering into the hedge agreements, we mitigate the effect on our cash flows of changes in the prices we receive for our oil, NGL and natural gas production.

	Oil (NYMEX-WTI) Weighted Average		NGL (NYMEX-WTI) Weighted Average		Natural Gas (NYMEX-Henry Hub) Weighted Average	
Term	**$/Bbl**	**Bbls/d**	**$/Bbl**	**Bbls/d**	**$/Mmbtu**	**Mmbtu/d**
2013	$ 95.45	1,933	$ 41.99	589	$ 5.09	20,871
2014	$ 95.93	1,590	$ 34.11	504	$ 5.53	16,649
2015	$ 94.72	1,152	$		$ 5.72	15,069
2016	$ 86.02	1,089	$		$ 4.29	14,887
2017	$ 85.75	545	$		$ 4.61	13,824

The following table summarizes, for the periods presented, our natural gas basis swaps in place as of June 30, 2013. These contracts are designed to effectively fix a price differential between the NYMEX-Henry Hub price and the index price at which the physical natural gas is sold.

	Centerpoint East		Houston Ship Channel		WAHA		TEXOK	
Term	$/Mmbtu	Mmbtu/d	$/Mmbtu	Mmbtu/d	$/Mmbtu	Mmbtu/d	$/Mmbtu	Mmbtu/d
2013	$ (0.1873)	7,987	$ (0.0837)	4,527	$ (0.1172)	6,581	$ (0.0990)	1,140
2014	$ (0.2121)	6,459	$ (0.0835)	3,475	$ (0.1290)	5,245	$ (0.1220)	919
2015	$ (0.2291)	5,939	$ (0.0959)	3,031	$ (0.1380)	4,777	$ (0.1334)	846
2016	$		$ (0.0810)	2,691	$ (0.1326)	4,408	$ (0.0975)	784

The following table summarizes, for the periods presented, our oil basis swaps in place as of June 30, 2013. These contracts are designed to effectively fix a price differential between the NYMEX-WTI price and the index price at which the physical oil is sold.

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Term		Midland-Cushing $/Bbl	Bbl/d
2013	$	(1.2500)	1,303
2014	$	(1.0000)	1,124

Cash Flows

Cash flows provided (used) by type of activity were as follows for the periods indicated (in thousands):

	Six Months Ended June 30, 2013		2012	
Net cash provided by (used in):				
Operating activities	$	27,115	$	41,136
Investing activities		(14,375)		(21,342)
Financing activities		(11,315)		(16,651)

Operating Activities.

Net cash provided by operating activities was approximately $27.1 million and $41.1 million for the six months ended June 30, 2013 and 2012, respectively. Revenues fluctuate due to the volatility of commodity prices, and therefore our cash provided by operating activities is impacted by the prices received for oil and natural gas sales, as well as levels of production volumes and operating expenses.

Our working capital totaled $19.7 million and $19.4 million at June 30, 2013 and December 31, 2012, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $4.9 million and $3.5 million at June 30, 2013 and December 31, 2012, respectively.

Investing Activities.

Net cash used in investing activities was approximately $14.4 million and $21.3 million for the six months ended June 30, 2013 and 2012, respectively, which primarily represented additions to our property and equipment balances during the period.

Financing Activities.

Net cash used in financing activities was approximately $11.3 million for the six months ended June 30, 2013, and consisted of net proceeds received from an equity offering of approximately $59.5 million and net borrowings under the Credit Agreement of $14.0 million offset by contributions and distributions to Lime Rock Resources associated with acquisitions of $61.4 million and distributions to unitholders of $23.4 million.

Net cash used in financing activities was approximately $16.7 million for the six months ended June 30, 2012, which included distributions paid to our unitholders of $15.9 million, contributions and distributions to Lime Rock Resources of $67.2 million and deferred financing costs of $0.5 million, offset by net borrowings of $67.0 million.

Outlook

We expect to spend approximately $32.0 million in total capital expenditures in 2013, of which approximately $20.3 million represents maintenance capital expenditures, on the development of our oil and natural gas properties.

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.4750 per unit per quarter ($1.90 per unit on an annualized basis). Based on the number of common units, subordinated units and general partner units outstanding as of August 2, 2013, quarterly distributions to all of our unitholders at the minimum quarterly distribution rate would total approximately $12.4

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million. We recently announced an increase to our quarterly distribution for the second quarter of 2013. Our current distribution is $0.485 per unit ($1.94 per unit on an annualized basis), or $12.7 million in aggregate. Our board of directors determines our distribution each quarter and there is no guarantee that the board will maintain or increase our current quarterly distribution in future periods.

We intend to pursue acquisitions of long-lived, low-risk producing oil and natural gas properties with reserve exploitation potential. We would expect to finance any significant acquisition of oil and natural gas properties in 2013 through external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities.

Off-Balance Sheet Arrangements

As of June 30, 2013, we had no off-balance sheet arrangements.

Critical Accounting Policies and Estimates

There have been no material changes to our critical accounting policies from those described in our 2012 Annual Report.

Recently Issued Accounting Pronouncements

Refer to Note 2 of the consolidated condensed financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes to the commodity price risk, interest rate risk and counterparty and customer credit risk discussed in our Annual Report on Form 10-K for the year ended December 31, 2012 under the caption Management s Discussion and Analysis or Financial Condition and Results of Operations Quantitative and Qualitative Disclosure About Market Risk.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act, as amended (the Exchange Act), we have evaluated, under the supervision and with the participation of our management, including our principal executive officers and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officers and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Our principal executive officers and principal financial officer, with the participation of management, have concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of June 30, 2013.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, neither we nor our general partner is currently a party to any material legal proceedings. In addition, we are not aware of any significant legal or governmental proceedings against us or our general partner, or contemplated to be brought against us or our general partner, under the various environmental protection statues to which we or our general partner is subject.

Item 1A. Risk Factors.

There have been no material changes to the risk factors described in our Annual Report on Form 10-K for the year ended December 31, 2012.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

None.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of LRR Energy, L.P. dated as of April 28, 2011 (incorporated by reference to Exhibit 3.1 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.2	First Amended and Restated Agreement of Limited Partnership of LRR Energy, L.P. dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Annual Report on Form 10-K (SEC File No. 001-35344), filed on March 27, 2012).
3.3	Certificate of Formation of LRE GP, LLC dated as of April 28, 2011 (incorporated by reference to Exhibit 3.4 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of LRE GP, LLC dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
31.1*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.

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31.3*	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
32.1*	Certification by Co-Chief Executive Officers and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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

** Submitted electronically herewith

In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this Quarterly Report on Form 10-Q shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	LRR Energy, L.P.	
	By:	**LRE GP, LLC,** its General Partner
Date: August 7, 2013	By:	/s/ Eric Mullins Eric Mullins Co-Chief Executive Officer
Date: August 7, 2013		
	By:	/s/ Jaime R. Casas Jaime R. Casas Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)

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EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Limited Partnership of LRR Energy, L.P. dated as of April 28, 2011 (incorporated by reference to Exhibit 3.1 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.2	First Amended and Restated Agreement of Limited Partnership of LRR Energy, L.P. dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Annual Report on Form 10-K (SEC File No. 001-35344), filed on March 27, 2012).
3.3	Certificate of Formation of LRE GP, LLC dated as of April 28, 2011 (incorporated by reference to Exhibit 3.4 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of LRE GP, LLC dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
31.1*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.3*	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
32.1*	Certification by Co-Chief Executive Officers and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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.

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