DORCHESTER MINERALS, L.P.
Form 10-Q
November 07, 2013
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, DC. 20549

FORM 10-Q

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

For the quarterly period ended **September 30, 2013**

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission file number **000-50175**

DORCHESTER MINERALS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**81-0551518**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3838 Oak Lawn Avenue, Suite 300, Dallas, Texas 75219

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(214) 559-0300**

None

(Former name, former address and former fiscal year, if changed since last report)

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 No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer", “accelerated filer” and “smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of November 7, 2013, 30,675,431 common units representing limited partnership interests were outstanding.

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

Statements included in this report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements disc future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. In this report, the term “Partnership,” as well as the terms “DMLP,” “us,” “our,” “we,” and “its” are sometimes us as abbreviated references to Dorchester Minerals, L.P. itself or Dorchester Minerals, L.P. and its related entities.

These forward-looking statements are based upon management’s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and, therefore, involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements for a number of important reasons. Examples of such reasons include, but are not limited to, changes in the price or demand for oil and natural gas, changes in the operations on or development of our properties, changes in economic and industry conditions and changes in regulatory requirements (including changes in environmental requirements) and our financial position, business strategy and other plans and objectives for future operations. These and other factors are set forth in our filings with the Securities and Exchange Commission.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other “forward-looking” information. Before you invest, you should be aware that the occurrence of any of the events described in this report could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common units could decline, and you could lose all or part of your investment.

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

See attached financial statements on the following pages.

DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

CONDENSED CONSOLIDATED BALANCE SHEETS

(In Thousands)

	September 30, 2013 (unaudited)	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,765	$ 13,792
Trade and other receivables	7,027	5,806
Net profits interests receivable - related party	4,366	6,472
Prepaid expenses	13	-
Total current assets	27,171	26,070
Other non-current assets	19	19
Total	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	344,196	344,196
Accumulated full cost depletion	(256,759)	(246,595)
Total	87,437	97,601
Leasehold improvements	512	512
Accumulated amortization	(439)	(402)
Total	73	110
Total assets	$ 114,700	$ 123,800
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 1,491	$ 448
Current portion of deferred rent incentive	39	39
Total current liabilities	1,530	487
Deferred rent incentive less current portion	20	50
Total liabilities	1,550	537

Commitments and contingencies (Note 2)		
Partnership capital:		
General partner	3,321	3,625
Unitholders	109,829	119,638
Total partnership capital	113,150	123,263
Total liabilities and partnership capital	$ 114,700	$ 123,800

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

DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

CONDENSED CONSOLIDATED INCOME STATEMENTS

(In Thousands except Income per Unit)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Operating revenues:				
Royalties	$15,031	$11,567	$39,843	$35,929
Net profits interests	1,365	1,606	6,972	2,350
Lease bonus	27	1,128	105	4,531
Other	17	7	33	173
Total operating revenues	16,440	14,308	46,953	42,983
Costs and expenses:				
Operating, including production taxes	1,340	1,434	3,795	3,665
Depletion and amortization	3,547	3,999	10,201	12,793
General and administrative expenses	835	745	2,707	2,429
Total costs and expenses	5,722	6,178	16,703	18,887
Operating income	10,718	8,130	30,250	24,096
Other income (expense), net	31	(1)	172	11
Net income	$10,749	$8,129	$30,422	$24,107
Allocation of net income:				
General partner	$399	$293	$1,058	$918
Unitholders	$10,350	$7,836	$29,364	$23,189
Net income per common unit (basic and diluted)	$0.34	$0.26	$0.96	$0.76
Weighted average common units outstanding	30,675	30,675	30,675	30,675

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

DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
Net cash provided by operating activities	$42,508	$44,036
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(40,535)	(45,928)
Increase (decrease) in cash and cash equivalents	1,973	(1,892)
Cash and cash equivalents at beginning of period	13,792	14,238
Cash and cash equivalents at end of period	$15,765	$12,346

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

DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1 Basis of Presentation: Dorchester Minerals, L.P. is a publicly traded Delaware limited partnership that was formed in December 2001, and commenced operations on January 31, 2003. The consolidated financial statements include the accounts of Dorchester Minerals, L.P. and its wholly-owned subsidiaries Dorchester Minerals Oklahoma LP, Dorchester Minerals Oklahoma GP, Inc., Maecenas Minerals LLP, and Dorchester-Maecenas GP LLC. All significant intercompany balances and transactions have been eliminated in consolidation.

The condensed consolidated financial statements reflect all adjustments (consisting only of normal and recurring adjustments unless indicated otherwise) that are, in the opinion of management, necessary for the fair presentation of our financial position and operating results for the interim period. Interim period results are not necessarily indicative of the results for the calendar year. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information. Per-unit information is calculated by dividing the income or loss applicable to holders of our Partnership's common units by the weighted average number of units outstanding. The Partnership has no potentially dilutive securities and, consequently, basic and dilutive income per unit do not differ. These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership's annual report on Form 10-K for the year ended December 31, 2012.

Fair Value of Financial Instruments — The carrying amount of cash and cash equivalents, trade receivables and payables approximates fair value because of the short maturity of those instruments. These estimated fair values may not be representative of actual values of the financial instruments that could have been realized as of quarter close or that will be realized in the future.

2 Contingencies: On January 27, 2006, plaintiff Rapp sued the operating partnership for underpayment of royalty on properties owned and operated in Texas County, Oklahoma. Plaintiff sought certification of a class action. A $500,000 reserve was recorded in Net Profits Revenues on the financial statements in the first quarter of 2012. On October 18, 2012, the District Court approved a class settlement between the parties in the amount of $500,000 plus immaterial future royalty amounts on fuel gas. During December 2012, the operating partnership paid the settlement amount and the litigation was dismissed.

The Partnership and the operating partnership are involved in other legal and/or administrative proceedings arising in the ordinary course of their businesses, none of which have predictable outcomes and none of which are believed to have any significant effect on consolidated financial position, cash flows, or operating results.

3 <u>Distributions to Holders of Common Units:</u> Unitholder cash distributions per common unit since 2009 have been:

	Per Unit Amount				
	2013	2012	2011	2010	2009
First quarter	$0.448209	$0.541883	$0.426745	$0.449222	$0.401205
Second quarter	$0.395583	$0.456351	$0.417027	$0.412207	$0.271354
Third quarter	$0.455287	$0.343252	$0.455546	$0.471081	$0.286968
Fourth quarter		$0.433232	$0.448553	$0.354074	$0.321540

Distributions from first quarter of 2010 through the present were paid on 30,675,431 units; distributions from the second quarter of 2009 through the fourth quarter of 2009 were paid on 29,840,431 units; previous distributions were paid on 28,240,431 units. The third quarter 2013 distribution was paid on October 31, 2013. Fourth quarter distributions shown above are paid in the first calendar quarter of the following year. Our partnership agreement requires the next cash distribution to be paid by February 15, 2014.

DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

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

The following discussion contains forward-looking statements. For a description of limitations inherent in forward-looking statements, see page 1 of this Form 10-Q.

Overview

We own producing and nonproducing mineral, royalty, overriding royalty, net profits and leasehold interests. We refer to these interests as the Royalty Properties. We currently own Royalty Properties in 574 counties and parishes in 25 states.

We own net profits overriding royalty interests (referred to as the Net Profits Interests, or "NPIs") in various properties owned by Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner. We refer to Dorchester Minerals Operating LP as the "operating partnership" or "DMOLP." We receive monthly payments equaling 96.97% of the net profits actually realized by the operating partnership from these properties in the preceding month. In the event costs exceed revenues on a cash basis in a given month for properties subject to a Net Profits Interest, no payment is made and any deficit is accumulated and carried over and reflected in the following month's calculation of net profit.

The Minerals NPI (one of the six) owns certain cost bearing interests that were either in existence at the time of our formation, or created subsequent to our formation but associated with nonproducing mineral, royalty and leasehold interest properties acquired upon our formation. The Minerals NPI achieved a cumulative net profit status on September 30, 2011 as a result of its cumulative net revenue exceeding cumulative operating and actual and budgeted capital expenditures and development costs. Subsequent Minerals NPI amounts and payments distributed are:

		Distribution	
NPI Period Ended	**NPI**	**Amount**	**Period**
Nov. 30, 2011	$1,347,000	$1,306,000	4th Qtr. 2011
Feb. 29, 2012	$709,000	$688,000	1st Qtr. 2012

May 31, 2012	$354,000	$343,000	2nd Qtr. 2012
Aug. 31, 2012	$395,000	$383,000	3rd Qtr. 2012
Nov. 30, 2012	$769,000	$746,000	4th Qtr. 2012
Feb. 28, 2013	$729,000	$707,000	1st Qtr. 2013
May 31, 2013	$452,000	$438,000	2nd Qtr. 2013
Aug. 31, 2013	$650,000	$631,000	3rd Qtr. 2013

Prior to the Minerals NPI achieving a cumulative payout status, activity attributable to the Minerals NPI was not reflected in our consolidated financial statements in accordance with generally accepted accounting principles. Effective third quarter 2011, our consolidated financial statements reflect activity attributable to the Minerals NPI, and include cash receipts and disbursements and accrued revenues and costs not yet received or paid by the NPI. Our financial statements reflect such information regardless of its net profit status on a cumulative or reporting period basis recorded by the Partnership. Net Profits Interest revenue recorded by the Partnership attributable to a Net Profits Interest that is in deficit status is limited such that no loss is recorded, as the Partnership is not liable for any of the operating partnership's commitments or obligations.

As of September 30, 2013, each of the six NPIs have previously had cumulative revenue that exceeded cumulative costs, such excess constituting net proceeds on which NPI payments were determined. In the event an NPI has a deficit of cumulative revenue versus cumulative costs, the deficit will be borne solely by the operating partnership. The Minerals NPI and one minor NPI are in a deficit status as of September 30, 2013 primarily due to drilling activity.

Commodity Price Risks

Our profitability is affected by oil and natural gas market prices. Oil and natural gas prices have fluctuated significantly in recent years in response to changes in the supply and demand for oil and natural gas in the market along with domestic and international political and economic conditions.

Results of Operations

Three and Nine Months Ended September 30, 2013 as compared to Three and Nine Months Ended September 30, 2012

Normally, our period-to-period changes in net income and cash flows from operating activities are principally determined by changes in oil and natural gas sales volumes and prices. Our portion of oil and natural gas sales and weighted average prices were:

	Three Months Ended			Nine Months Ended	
	September 30,		June 30,	September 30,	
	2013	2012	2013	2013	2012
Accrual basis sales volumes:					
Royalty properties gas sales (mmcf)	1,327	1,273	1,207	3,811	4,588
Royalty properties oil sales (mbbls)	104	88	91	282	267
NPI gas sales (mmcf)	1,050	1,067	940	3,057	3,253
NPI oil sales (mbbls)	34	20	38	93	51
Accrual basis weighted average sales price:					
Royalty properties gas sales ($/mcf)	$3.28	$3.02	$3.84	$3.40	$2.50
Royalty properties oil sales ($/bbl)	$102.89	$88.39	$93.84	$95.28	$91.79
NPI gas sales ($/mcf)	$3.46	$2.76	$3.95	$3.57	$2.42
NPI oil sales ($/bbl)	$98.28	$86.54	$90.71	$93.02	$87.87
Accrual basis production and capital costs deducted under the NPIs ($/mcfe) (1)	$4.45	$2.61	$2.71	$3.51	$2.84

(1) Provided to assist in determination of revenues; applies only to NPI sales volumes and prices.

Natural gas sales volumes attributable to our Royalty Properties during the third quarter increased 4.2% from 1,273 mmcf in 2012 to 1,327 mmcf in 2013. The increase in natural gas sales volumes in the third quarter compared to the same period of 2012 is primarily due to one large suspense release of partnership production in the Fayetteville Shale. Natural gas sales volumes attributable to our Royalty Properties during the first nine months decreased 16.9% from 4,588 mmcf in 2012 to 3,811 mmcf in 2013. The decrease in natural gas sales for the first nine months of 2013 compared to the same period of 2012 is primarily due to natural reservoir declines and decreased activity in the Fayetteville Shale and the Barnett Shale. Oil sales volumes attributable to our Royalty Properties during the third quarter increased 18.2% from 88 mbbls in 2012 to 104 mbbls in 2013. Oil sales volumes attributable to our Royalty Properties during the first nine months increased 5.6% from 267 mbbls in 2012 to 282 mbbls in 2013. Both oil sales increases are due to activity in the Permian Basin and the Bakken Trend.

Natural gas sales volumes attributable to our NPIs during the third quarter of 2013 were 1,050 mmcf, a decrease of 1.6% from 1,067 mmcf in the same period of 2012. Natural gas volumes attributable to our NPIs during the first nine months decreased 6.0% from 3,253 mmcf in 2012 to 3,057 mmcf in the same period of 2013. Such decreases were due to natural reservoir declines and decreased activity in the Fayetteville Shale. Oil sales volumes attributable to our NPIs during the third quarter of 2013 were 34 mbbls, an increase of 70.0% from 20 mbbls during the same period of 2012. Oil sales volumes attributable to our NPIs during the first nine months increased 82.4% from 51 mbbls in 2012 to 93 mbbls in 2013. Both increases are primarily due to activity in the Permian Basin and the Bakken Trend.

The weighted average oil sales prices attributable to our interest in Royalty Properties increased 16.4% from $88.39/bbl during the third quarter of 2012 to $102.89/bbl during the third quarter of 2013 and increased 3.8% from $91.79/bbl during the first nine months of 2012 to $95.28/bbl during the same period of 2013. Weighted average natural gas sales prices from Royalty Properties increased 8.6% from $3.02/mcf during the third quarter of 2012 to $3.28/mcf during the third quarter of 2013 and increased 36.0% from $2.50/mcf during the first nine months of 2012 to $3.40/mcf during the same period of 2013. Both oil and natural gas price changes resulted from changing market prices.

Third quarter weighted average oil sales prices from the NPIs increased 13.6% from $86.54/bbl in 2012 to $98.28/bbl in 2013 and increased 5.9% from $87.87/bbl during the first nine months of 2012 to $93.02/bbl during the same period of 2013. Third quarter weighted average natural gas sales prices attributable to the NPIs increased 25.4% from $2.76/mcf during 2012 to $3.46/mcf in 2013 and increased 47.5% from $2.42/mcf during the first nine months of 2012 to $3.57/mcf during the same period of 2013. Both oil and natural gas price changes resulted from changing market prices.

Our third quarter net operating revenues increased 14.9% from $14,308,000 during 2012 to $16,440,000 during 2013. This increase is primarily a result of increased prices and volumes as discussed above offset by lower lease bonus income and increased capital costs and commitments by the operating partnership on properties underlying two NPIs. Our first nine months net operating revenues increased 9.2% from $42,983,000 during 2012 to $46,953,000 during 2013. These increases were primarily a result of increased oil and natural gas sales prices and changing sales volumes, both discussed above, partially offset by lower lease bonus income.

Costs and expenses of $5,722,000 and $16,703,000 during the third quarter and first nine months of 2013, respectively, were down 7.4% and 11.6%, compared to $6,178,000 and $18,887,000, respectively, during the same periods of 2012. In both periods of 2013, increased general and administrative costs and production taxes on higher revenues were offset by reduced ad valorem costs and depletion and amortization costs compared to the same periods of 2012.

General and administrative expenses of $835,000 and $2,707,000 during the third quarter and first nine months of 2013, respectively, were up 12.1% and 11.4%, compared to $745,000 and $2,429,000, respectively, during the same periods of 2012, primarily related to non-recurring Bakken Trend costs.

Depletion and amortization costs of $3,547,000 and $10,201,000 during the third quarter and first nine months of 2013, respectively, were down 11.3% and 20.3%, compared to $3,999,000 and $12,793,000, respectively, during the same periods of 2012. These reductions were due to the effects of upward reserve revisions at 2012 year-end and lower natural gas sales volumes during 2013.

Third quarter net income allocable to common units increased 32.1% from $7,836,000 during 2012 to $10,350,000 during 2013. First nine months common unit net income increased 26.6% from $23,189,000 during 2012 to $29,364,000 during 2013. In both periods, increased oil and natural gas sales prices and oil volumes were partially offset by increased capital costs and commitments by the operating partnership for drilling activities on properties underlying the NPIs, decreased natural gas sales volumes, and lease bonus income.

Net cash provided by operating activities increased 28.5% from $11,543,000 during the third quarter of 2012 to $14,830,000 during the third quarter of 2013 but decreased 3.5% from $44,036,000 during the first nine months of 2012 to $42,508,000 during the same period of 2013. Changes in both periods are due to changes in oil and natural gas prices and volumes offset by reduced lease bonus income and capital costs and commitments for drilling activities on the properties underlying the NPI properties.

In an effort to provide the reader with information concerning prices of oil and natural gas sales that correspond to our quarterly distributions, management calculates the weighted average price by dividing gross revenues received by the net volumes of the corresponding product without regard to the timing of the production to which such sales may be attributable. This “indicated price” does not necessarily reflect the contract terms for such sales and may be affected by transportation costs, location differentials, and quality and gravity adjustments. While the relationship between our cash receipts and the timing of the production of oil and natural gas may be described generally, actual cash receipts may be materially impacted by purchasers’ release of suspended funds and by purchasers’ prior period adjustments.

Cash receipts attributable to our Royalty Properties during the 2013 third quarter totaled approximately $13,800,000. These receipts generally reflect oil sales during June through August 2013 and natural gas sales during May through July 2013. The weighted average indicated prices for oil and natural gas sales received during the 2013 third quarter attributable to the Royalty Properties were $98.11/bbl and $3.65/mcf, respectively.

Cash receipts attributable to our NPIs during the 2013 third quarter totaled approximately $2,200,000. These receipts generally reflect oil and natural gas sales from the properties underlying the NPIs during May through July 2013. The weighted average indicated prices for oil and natural gas sales received during the 2013 third quarter attributable to our NPIs were $88.09/bbl and $3.84/mcf, respectively.

We received cash payments of approximately $170,000 from various sources during the third quarter of 2013, of which some are attributable to six consummated leases and pooling elections located in five counties and parishes in three states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to $500/acre.

We received division orders for, or otherwise identified, 161 new wells completed on our Royalty Properties and NPIs located in 32 counties and parishes in eight states during the third quarter of 2013. The operating partnership elected to participate during the third quarter of 2013 in 30 wells to be drilled on our NPI properties located in seven counties in two states.

Additional information concerning selected properties is summarized below:

APPALACHIAN BASIN — We own varying undivided perpetual mineral interests in approximately 31,000/24,000 gross/net acres in 19 counties in southern New York and northern Pennsylvania. Approximately 75% of those net acres are located in eastern Allegany and western Steuben Counties, New York—an area that some industry press reports suggest may be prospective for gas production from unconventional reservoirs, including the Marcellus Shale. However, development of these natural gas resources will be limited until remaining regulatory issues related to high-volume hydraulic fracturing are resolved. We continue to monitor industry activity and encourage dialogue with industry participants to determine the proper course of action regarding our interests in this area.

FAYETTEVILLE SHALE TREND OF NORTHERN ARKANSAS –- We own varying undivided perpetual mineral interests in approximately 23,000/11,000 gross/net acres located in Cleburne, Conway, Faulkner, Franklin, Johnson, Pope, Van Buren, and White Counties, Arkansas in an area commonly referred to as the “Fayetteville Shale” trend of the Arkoma Basin. Permits for 474 wells had been issued on these lands as of September 30, 2013, of which the operating partnership owns an interest in 235. In total, 459 wells were spud of which 426 were completed as producers, including wells for which we may not yet have received division orders or first payment.

HORIZONTAL BAKKEN, WILLISTON BASIN –- We own varying undivided perpetual mineral interests in approximately 70,000/9,000 gross/net acres located in Burke, Divide, Dunn, McKenzie, Mountrail and Williams Counties, North Dakota. Permits for 451 wells had been issued on these lands as of September 30, 2013. In total, 382 wells were spud, of which 315 were completed as producers including wells for which we may not yet have received division orders or first payment. In many instances we elected to become a non-consenting mineral owner—who, according to North Dakota law, is not obligated to pay well costs, receives a royalty equal to the weighted average of all leases in the unit or 16% (at the operator’s option) from the date of first production, and backs-in for its full working interest after the operator has recovered 150% of drilling and completion costs from the net cash flow. The back-in working interest, if any, is owned by the operating partnership subject to the Minerals NPI burden. Non-consenting mineral owners are not entitled to well data other than public information available from the North Dakota Industrial Commission. As of September 30, 2013, 28 of these wells had achieved 150% payout.

Market dynamics in the Bakken Trend have evolved resulting in higher lease bonus and royalty offers for unleased mineral interests. We are considering opportunities to sell a lease on our interests in this area, to combine our interests with others or to pursue alternative transaction structures. We have engaged the services of an investment bank in this matter. We can not project if, when or with whom we may elect to sell, lease or otherwise transact all or any part of our interests as a result of this process.

Liquidity and Capital Resources

Capital Resources

Our primary sources of capital are our cash flows from the NPIs and the Royalty Properties. Our only cash requirements are the distributions to our unitholders, the payment of oil and natural gas production and property taxes not otherwise deducted from gross production revenues and general and administrative expenses incurred on our behalf and allocated in accordance with our partnership agreement. Since the distributions to our unitholders are, by definition, determined after the payment of all expenses actually paid by us, the only cash requirements that may create liquidity concerns for us are the payments of expenses. Since most of these expenses vary directly with oil and natural gas sales prices and volumes, we anticipate that sufficient funds will be available at all times for payment of these expenses. See Note 3 of the Notes to the Condensed Consolidated Financial Statements for the amounts and dates of cash distributions to unitholders.

We are not directly liable for the payment of any exploration, development or production costs. We do not have any transactions, arrangements or other relationships that could materially affect our liquidity or the availability of capital resources. We have not guaranteed the debt of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt.

Pursuant to the terms of our partnership agreement, we cannot incur indebtedness, other than trade payables, (i) in excess of $50,000 in the aggregate at any given time or (ii) which would constitute “acquisition indebtedness” (as defined in Section 514 of the Internal Revenue Code of 1986, as amended).

Expenses and Capital Expenditures

Depending upon gas prices, the operating partnership plans to continue its efforts to increase production in Oklahoma with techniques that may include fracture treating, deepening, recompleting, and drilling. Costs vary widely and are not predictable as each effort requires specific engineering. Such activities by the operating partnership could influence the amount we receive from the NPIs as reflected in the accrual-basis production costs $/mcfe in the table under "Results of Operations."

The operating partnership owns and operates the wells, pipelines and natural gas compression and dehydration facilities located in Kansas and Oklahoma. The operating partnership does not anticipate incurring significant expense to replace these facilities at this time. These capital and operating costs are reflected in the NPI payments we receive from the operating partnership.

In 1998, Oklahoma regulations removed production quantity restrictions in the Guymon-Hugoton field and did not address efforts by third parties to persuade Oklahoma to permit infill drilling in the Guymon-Hugoton field. Infill drilling could require considerable capital expenditures. The outcome and the cost of such activities are unpredictable and could influence the amount we receive from the NPIs. The operating partnership believes it now has sufficient field compression and permits for vacuum operation for the foreseeable future.

Liquidity and Working Capital

Cash and cash equivalents totaled $15,765,000 at September 30, 2013 and $13,792,000 at December 31, 2012.

Critical Accounting Policies

We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this method, all such costs are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full cost ceiling is evaluated at the end of each quarter and when events indicate possible impairment.

The discounted present value of our proved oil and natural gas reserves is a major component of the ceiling calculation and requires many subjective judgments. Estimates of reserves are forecasts based on engineering and geological analyses. Different reserve engineers may reach different conclusions as to estimated quantities of natural gas or crude oil reserves based on the same information. Our reserve estimates are prepared by independent consultants. The passage of time provides more qualitative information regarding reserve estimates, and revisions are made to prior estimates based on updated information. However, there can be no assurance that significant revisions will not be necessary in the future. Significant downward revisions could result in an impairment representing a non-cash charge to income. In addition to the impact on the calculation of the ceiling test, estimates of proved reserves are also a major component of the calculation of depletion.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of our reserves are objectively determined. The ceiling test calculation requires use of the unweighted arithmetic average of the first day of the month price during the 12-month period ending on the balance sheet date and costs in effect as of the last day of the accounting period, which are generally held constant for the life of the properties. As a result, the present value is not necessarily an indication of the fair value of the reserves. Oil and natural gas prices have historically been volatile and the prevailing prices at any given time may not reflect our Partnership’s or the industry’s forecast of future prices.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. For example, estimates of uncollected revenues and unpaid expenses from Royalty Properties and NPI properties operated by non-affiliated entities are particularly subjective due to our inability to gain accurate and timely information. Therefore, actual results could differ from those estimates.

item 3. Quantitative and Qualitative Disclosures About Market Risk

The following information provides quantitative and qualitative information about our potential exposures to market risk. The term “market risk” refers to the risk of loss arising from adverse changes in oil and natural gas prices, interest rates and currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses but, rather, indicators of possible losses.

Market Risk Related to Oil and Natural Gas Prices

Essentially all of our assets and sources of income are from Royalty Properties and NPIs, which generally entitle us to receive a share of the proceeds based on oil and natural gas production from those properties. Consequently, we are subject to market risk from fluctuations in oil and natural gas prices. Pricing for oil and natural gas production has been unpredictable for several years. We do not anticipate entering into financial hedging activities intended to reduce our exposure to oil and natural gas price fluctuations.

Absence of Interest Rate and Currency Exchange Rate Risk

We do not anticipate having a credit facility or incurring any debt, other than trade debt. Therefore, we do not expect interest rate risk to be material to us. We do not anticipate engaging in transactions in foreign currencies that could expose us to foreign currency related market risk.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, our principal executive officer and principal financial officer carried out an evaluation of the effectiveness of our disclosure controls and procedures. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective.

Changes in Internal Controls

There were no changes in our internal controls (as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934) during the quarter ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

The Partnership and the operating partnership are involved in legal and/or administrative proceedings arising in the ordinary course of their businesses, none of which have predictable outcomes and none of which are believed to have any significant effect on consolidated financial position, cash flows, or operating results.

Item 6. Exhibits

See the attached Index to Exhibits.

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.

DORCHESTER MINERALS, L.P.

By: Dorchester Minerals Management LP
its General Partner

By: Dorchester Minerals Management GP LLC
its General Partner

By: /s/ William Casey McManemin
William Casey McManemin
Date: November 7, 2013 Chief Executive Officer

By: /s/ H.C. Allen, Jr.
H.C. Allen, Jr.
Date: November 7, 2013 Chief Financial Officer

INDEX TO EXHIBITS

Number	Description
3.1	Certificate of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.1 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.2	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.2 to Dorchester Minerals' Report on Form 10-K filed for the year ended December 31, 2002)
3.3	Certificate of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.4	Amended and Restated Limited Partnership Agreement of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.5	Certificate of Formation of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.7 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.6	Amended and Restated Limited Liability Company Agreement of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.6 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.7	Certificate of Formation of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.8	Limited Liability Company Agreement of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.9	Certificate of Limited Partnership of Dorchester Minerals Operating LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.10	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Operating LP (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
31.1*	Certification of Chief Executive Officer of the Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer of the Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934

32.1**	Certification of Chief Executive Officer of the Partnership pursuant to 18 U.S.C. Sec. 1350
32.2**	Certification of Chief Financial Officer of the Partnership pursuant to 18 U.S.C. Sec. 1350 (contained within Exhibit 32.1 hereto)
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 Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

**Furnished herewith