DORCHESTER MINERALS, L.P.
Form 10-Q
November 07, 2014
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, 2014**

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 6, 2014, 30,675,431 common units representing limited partnership interests were outstanding.

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(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, 2014 (unaudited)	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,899	$ 15,175
Trade and other receivables	6,263	6,508
Net profits interests receivable - related party	8,269	6,515
Prepaid expenses	12	-
Total current assets	30,443	28,198
Other non-current assets	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	340,580	344,196
Accumulated full cost depletion	(267,545)	(259,689)
Total	73,035	84,507
Leasehold improvements	512	512
Accumulated amortization	(488)	(451)
Total	24	61
Total assets	$ 103,521	$ 112,785
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 1,427	$ 911
Current portion of deferred rent incentive	20	39
Total current liabilities	1,447	950
Deferred rent incentive less current portion	-	11
Total liabilities	1,447	961
Commitments and contingencies (Note 2)		

Partnership capital:		
General partner	2,932	3,250
Unitholders	99,142	108,574
Total partnership capital	102,074	111,824
Total liabilities and partnership capital	$ 103,521	$ 112,785

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,	
	2014	2013	2014	2013
Operating revenues:				
Royalties	$13,638	$15,031	$43,876	$39,843
Net profits interests	1,603	1,365	5,913	6,972
Lease bonus	392	27	1,131	105
Other	83	17	108	33
Total operating revenues	15,716	16,440	51,028	46,953
Costs and expenses:				
Operating, including production taxes	1,345	1,340	4,321	3,795
Depletion and amortization	2,610	3,547	7,893	10,201
General and administrative expenses	796	835	2,991	2,707
Total costs and expenses	4,751	5,722	15,205	16,703
Operating income	10,965	10,718	35,823	30,250
Other income, net	4	31	712	172
Net income	$10,969	$10,749	$36,535	$30,422
Allocation of net income:				
General partner	$400	$399	$1,316	$1,058
Unitholders	$10,569	$10,350	$35,219	$29,364
Net income per common unit (basic and diluted)	$0.35	$0.34	$1.15	$0.96
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.

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2014	2013
Net cash provided by operating activities	$47,009	$42,508
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(46,285)	(40,535)
Increase in cash and cash equivalents	724	1,973
Cash and cash equivalents at beginning of period	15,175	13,792
Cash and cash equivalents at end of period	$15,899	$15,765

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

DORCHESTER MINERALS, L.P.

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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, 2013.

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:** The Partnership and Dorchester Minerals Operating LP (“operating partnership” or “DMOLP”, a Delaware limited partnership owned directly and indirectly by our general partner) 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 the consolidated financial position, cash flows, or operating results.

3 <u>Distributions to Holders of Common Units:</u> Unitholder cash distributions per common unit since 2010 have been:

	Per Unit Amount				
	2014	2013	2012	2011	2010
First quarter	$0.496172	$0.448209	$0.541883	$0.426745	$0.449222
Second quarter	$0.490861	$0.395583	$0.456351	$0.417027	$0.412207
Third quarter	$0.447805	$0.455287	$0.343252	$0.455546	$0.471081
Fourth quarter		$0.468560	$0.433232	$0.448553	$0.354074

Distributions beginning with the first quarter of 2010 were paid on 30,675,431 units. The third quarter 2014 distribution was paid on October 30, 2014. 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, 2015.

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4 **New Accounting Pronouncements:** In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP.

The standard is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are currently evaluating the impact of our pending adoption of ASU 2014-09 on our consolidated financial statements and have not yet determined the method by which we will adopt the standard in 2017.

5 **Property Sale:** On September 24, 2014 (the “Closing Date”), the Partnership and DMOLP closed a transaction selling Kansas working interests in the Hugoton NPI to Linn Energy. The sale was effective June 1, with an initial purchase price of $3,800,000. Final net proceeds from the sale are subject to adjustments until 120 days after the Closing Date. In accordance with full cost accounting for oil and gas properties, the proceeds have been credited to the full cost pool as the sale did not represent a significant portion of the Partnership’s reserves. On October 20, 2014, the Partnership received payment from the Hugoton NPI in the amount of $4,041,000, which reflects, in part, proceeds from the sale.

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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.

Each of our five 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.

Prior to the Minerals NPI (one of the five NPIs) 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 ("GAAP"). 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 will now continue to reflect such information regardless of its net profit status on a cumulative or reporting period basis. As of September 30, 2014, the Minerals NPI is currently in temporary deficit of $11,500,000, primarily due to budgeted capital expenditures.

The last payment attributable to the Minerals NPI was declared as of July 31, 2013, at which time cash on hand equaled outstanding capital commitments (resulting in a zero balance, i.e. neither a deficit nor surplus). Since that time, DMLOP has received production revenue, paid operating and capital expenses and made additional capital commitments, resulting in the temporary deficit described above. Set forth below is a summary calculation of this activity and the calculation of the Minerals NPI deficit as of September 30, 2014:

Cash on Hand @ 07/31/2013	$5,000,000
Cumulative Revenue During Period	24,400,000
Cumulative Expense During Period	(5,600,000)
Cumulative Operating Income During Period	18,800,000
Cumulative CAPEX Spent During Period	(13,500,000)
Cash Flow During Period	5,300,000
Cash on Hand @ 09/30/2014	10,300,000
Capital Commitments @ 07/31/2013	(5,000,000)
Change in Commitments During Period	(16,800,000)
Capital Commitments @ 09/30/2014	(21,800,000)
Cumulative Surplus (Deficit) @ 09/30/2014	$(11,500,000)

Note: Period runs from August 1, 2013 through September 30, 2014

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, 2014 as compared to Three and Nine Months Ended September 30, 2013

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 September 30, 2014	2013[2]	Nine Months Ended September 30, 2014	2013[2]
Accrual basis sales volumes:				
Royalty properties gas sales (mmcf)	854	1,327	2,702	3,811
Royalty properties oil sales (mbbls)	131	104	381	282
NPI gas sales (mmcf)	853	1,050	2,613	3,057
NPI oil sales (mbbls)	66	34	159	93
Accrual basis weighted average sales price:				
Royalty properties gas sales ($/mcf)	$ 3.59	$ 3.28	$ 4.44	$ 3.40
Royalty properties oil sales ($/bbl)	$ 81.06	$ 102.89	$ 83.66	$ 95.28
NPI gas sales ($/mcf)	$ 3.84	$ 3.46	$ 4.66	$ 3.57
NPI oil sales ($/bbl)	$ 88.06	$ 98.28	$ 87.07	$ 93.02
	$ 9.33	$ 4.45	$ 6.86	$ 3.51

Accrual basis production and capital costs deducted under the NPIs ($/mcfe) [1]

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

(2) Volumes attributable to prior periods have not been adjusted to reflect the change in plant products methodology adopted January 1, 2014.

As of January 1, 2014, we adopted a change in the methodology used to account for plant products volumes. These products were previously converted into a natural gas equivalent volume, but will now be converted into a liquid equivalent volume. As a result, volumes attributable to such products will no longer contribute to natural gas sales volumes, but will instead be included with oil sales volumes. This change in methodology will affect reported results effective as of January 1, 2014, including a reduction in accrued gas equivalent volumes for Royalty and NPI properties of 182 mmcfe and 49 mmcfe, respectively, and an increase in accrued oil equivalent volumes for Royalty and NPI properties of 12 mbbls and 3 mbbls, respectively. This change in methodology was recommended by our independent reserve engineers and we feel it more accurately reflects the underlying character of our plant products and their contribution to our production results.

Natural gas sales volumes attributable to our Royalty Properties during the third quarter and first nine months decreased 35.6% and 29.1% from 1,327 mmcf and 3,811 mmcf in 2013 to 854 mmcf and 2,702 mmcf in the same periods of 2014, respectively. The decreases in natural gas sales volumes in the third quarter and first nine months of 2014 compared to the same periods of 2013 are primarily due to the above mentioned change in accounting for plant products and natural reservoir declines. Oil sales volumes attributable to our Royalty Properties during the third quarter and first nine months increased 26.0% and 35.1% from 104 mbbls and 282 mbbls in 2013 to 131 mbbls and 381 mbbls in the same periods of 2014, respectively. The increases in oil sales volumes are a result of the above mentioned change in accounting for plant products and robust activity in the Permian Basin and the Bakken Trend.

Natural gas sales volumes attributable to our NPIs during the third quarter and first nine months of 2014 were 853 mmcf and 2,613 mmcf, decreases of 18.8% and 14.5% from 1,050 mmcf and 3,057 mmcf in the same periods of 2013, respectively. The decreases were primarily due to the above mentioned change in accounting for plant products and natural reservoir declines in the Fayetteville Shale. Oil sales volumes attributable to our NPIs during the third quarter and first nine months of 2014 were 66 mbbls and 159 mbbls, increases of 94.1% and 71.0% from 34 mbbls and 93 mbbls during the same periods of 2013., respectively. The increase in oil sales volumes are a result of the above mentioned change in accounting for plant products and robust activity in the Permian Basin and the Bakken Trend.

The weighted average oil sales prices attributable to our interest in Royalty Properties decreased 21.2% from $102.89/bbl during the third quarter of 2013 to $81.06/bbl during the third quarter of 2014. Weighted average natural gas sales prices from Royalty Properties increased 9.5% from $3.28/mcf during the third quarter of 2013 to $3.59/mcf during the third quarter of 2014. The weighted average oil sales prices attributable to our interest in Royalty Properties decreased 12.2% from $95.28/bbl during the first nine months of 2013 to $83.66/bbl during the first nine months of 2014. Weighted average natural gas sales prices from Royalty Properties increased 30.6% from $3.40/mcf during the first nine months of 2013 to $4.44/mcf during the first nine months of 2014. Both oil and natural gas price changes resulted from changing market prices.

Third quarter weighted average oil sales prices from the NPIs decreased 10.4% to $88.06/bbl in 2014 compared to $98.28/bbl in 2013, while average oil prices for the first nine months of 2014 decreased 6.4% to $87.07/bbl in 2014 compared to $93.02/bbl in the same period of 2013. Third quarter weighted average natural gas sales prices attributable to the NPIs increased 11.0% from $3.46/mcf during 2013 to $3.84/mcf in 2014, while average natural gas sales prices for the first nine months of 2014 increased 30.5% to $4.66/mcf compared to $3.57/mcf in the same period of 2013. Both oil and natural gas price changes resulted from changing market prices.

Our third quarter net operating revenues decreased 4.4% from $16,440,000 during 2013 to $15,716,000 during the same period of 2014. Our first nine months net operating revenues increased 8.7% from $46,953,000 during 2013 to $51,028,000 during the same period of 2014. These changes are primarily a result of changes in prices and volumes as discussed above along with increased lease bonus income.

Costs and expenses were down 17.0% at $4,751,000 during the third quarter of 2014 compared to $5,722,000 in the same period of 2013 due to reduced depletion costs. Costs and expenses during the first nine months of 2014 were down 9.0% from $16,703,000 in 2013 to $15,205,000 in 2014. In both periods due to reduced depletion costs were offset primarily by increased production costs due to increased revenue and, to a lesser degree, general and administrative expenses.

General and administrative expenses of $796,000 during the third quarter of 2014 were down 4.7% compared to $835,000 during the same period of 2013. General and administrative expenses of $2,991,000 during the first nine months of 2014 were up 10.5% compared to $2,707,000 during the same period of 2013. Changes in both periods are primarily due to costs related to the Bakken Trend and the Fayetteville Shale.

Depletion and amortization costs of $2,610,000 and $7,893,000 during the third quarter and first nine months of 2014 were down 26.4% and 22.6% compared to $3,547,000 and $10,201,000, respectively, during the same periods of 2013. The reduction was due to the effects of upward reserve revisions at 2013 year-end and lower natural gas sales volumes during 2014.

Other income of $712,000 during the first nine months of 2014 was related to a first quarter 2014 settlement of a dispute on leases in North Dakota.

Third quarter and first nine months net income allocable to common units increased 2.1% and 19.9% from $10,350,000 and $29,364,000 during 2013 to $10,569,000 and $35,219,000, respectively, during 2014. Increased oil and natural gas sales prices, oil volumes, and lease bonus income were partially offset by increased capital costs and commitments by the operating partnership for drilling activities on properties underlying the NPIs, decreased oil sales prices, and decreased natural gas sales volumes.

Net cash provided by operating activities was about the same at $14,830,000 during the third quarter of 2013 compared to $14,727,000 during the same period of 2014. Net cash provided by operating activities increased 10.6% from $42,508,000 during the first nine months of 2013 to $47,009,000 during the same period of 2014. Both increases are due to changes in oil prices and volumes and increased lease bonus income. These increases were partially offset by 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 2014 third quarter totaled approximately $13,600,000. These receipts generally reflect oil sales during June through August 2014 and natural gas sales during May through July 2014. The weighted average indicated prices for oil and natural gas sales received during the 2014 third quarter attributable to the Royalty Properties were $85.60/bbl and $4.15/mcf, respectively.

Cash receipts attributable to our NPIs during the 2014 third quarter totaled approximately $1,800,000. These receipts generally reflect oil and natural gas sales from the properties underlying the NPIs during May through July 2014. The weighted average indicated prices for oil and natural gas sales received during the 2014 third quarter attributable to our NPIs were $89.50/bbl and $4.40/mcf, respectively.

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 531 wells had been issued on these lands as of September 30, 2014, of which the operating partnership owns an interest in 248. In total, 515 wells were spud of which 484 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 586 wells had been issued on these lands as of September 30, 2014. In total, 531 wells were spud, of which 428 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, 2014, 40 of these wells had achieved 150% payout.

We have and will continue to utilize a range of transaction structures for our unleased mineral interests including leasing to third parties, working interest participation through the operating partnership, electing non-consent under North Dakota law, or a combination thereof.

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 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 $15,899,000 at September 30, 2014 and $15,175,000 at December 31, 2013.

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, 2014 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 6, 2014		Chief Executive Officer
	By:	/s/ H.C. Allen, Jr.
		H.C. Allen, Jr.
Date: November 6, 2014		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