DORCHESTER MINERALS, L.P.
Form 10-Q
November 03, 2017
**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, 2017**

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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", “accelerated filer”, “smaller reporting company", and “emerging growth 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 | Emerging growth company | |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act

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 3, 2017, 32,279,774 common units representing limited partnership interests were outstanding.

**TABLE OF CONTENTS**

**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)**

**(Unaudited)**

| | **September 30, 2017** | **December 31, 2016** |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 11,557 | $ 8,212 |
| Trade and other receivables | 5,210 | 4,332 |
| Net profits interests receivable - related party | 2,321 | 2,225 |
| Total current assets | 19,088 | 14,769 |
| | | |
| Other non-current assets | 31 | 19 |
| | | |
| Property and leasehold improvements - at cost: | | |
| Oil and natural gas properties (full cost method) | 363,186 | 340,563 |
| Accumulated full cost depletion | (294,583) | (288,163) |
| Total | 68,603 | 52,400 |
| | | |
| Leasehold improvements | 1,208 | 625 |
| Accumulated amortization | (625) | (602) |
| Total | 583 | 23 |
| | | |
| Total assets | $ 88,305 | $ 67,211 |
| **LIABILITIES AND PARTNERSHIP CAPITAL** | | |
| Current liabilities: | | |
| Accounts payable and other current liabilities | $ 1,774 | $ 252 |
| Current portion of deferred rent incentive | 15 | 23 |
| Total current liabilities | 1,789 | 275 |
| Deferred rent incentive less current portion | 462 | - |
| Total liabilities | 2,251 | 275 |

Commitments and contingencies (Note 2)

| | | |
|---|---|---|
| Partnership capital: | | |
| General partner | 1,693 | 1,809 |
| Unitholders | 84,361 | 65,127 |
| Total partnership capital | 86,054 | 66,936 |
| Total liabilities and partnership capital | $ 88,305 | $ 67,211 |

The accompanying 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** | | **Nine Months Ended** | |
|---|---|---|---|---|
| | **September 30,** | | **September 30,** | |
| | **2017** | **2016** | **2017** | **2016** |
| Operating revenues: | | | | |
| Royalties | $11,499 | $8,208 | $32,611 | $20,758 |
| Net profits interests | 737 | 1,589 | 2,706 | 3,320 |
| Lease bonus | 43 | 865 | 1,799 | 2,509 |
| Other | 201 | 17 | 644 | 227 |
| Total operating revenues | 12,480 | 10,679 | 37,760 | 26,814 |
| Costs and expenses: | | | | |
| Operating, including production taxes | 1,320 | 902 | 3,358 | 2,180 |
| Depreciation, depletion and amortization | 2,795 | 2,080 | 6,443 | 6,571 |
| General and administrative expenses | 1,141 | 1,050 | 3,764 | 3,967 |
| Total costs and expenses | 5,256 | 4,032 | 13,565 | 12,718 |
| Net income | $7,224 | $6,647 | $24,195 | $14,096 |
| Allocation of net income: | | | | |
| General partner | $273 | $230 | $903 | $496 |
| Unitholders | $6,951 | $6,417 | $23,292 | $13,600 |
| Net income per common unit (basic and diluted) | $0.22 | $0.21 | $0.75 | $0.44 |
| Weighted average common units outstanding (000's) | 32,280 | 30,675 | 31,222 | 30,675 |

The accompanying 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, | |
|---|---|---|
| | **2017** | **2016** |
| Net cash provided by operating activities | $31,274 | $21,563 |
| Cash flows provided by investing activities: | | |
| Cash contributed in acquisition of royalty interests | 437 | - |
| Capital expenditures | (106) | - |
| Total cash flows provided by investing activities | 331 | - |
| Cash flows used in financing activities: | | |
| Distributions paid to general partner and unitholders | (28,260) | (19,203) |
| Increase in cash and cash equivalents | 3,345 | 2,360 |
| Cash and cash equivalents at beginning of period | 8,212 | 7,136 |
| Cash and cash equivalents at end of period | $11,557 | $9,496 |
| Non-cash investing and financing activities: | | |
| Fair value of common units issued for acquisition of royalty interests | $23,183 | $- |

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

4

**DORCHESTER MINERALS, L.P.**

**(A Delaware Limited Partnership)**

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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 condensed 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 statement 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, 2016.

*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 <u>Commitments and</u> <u>Contingencies:</u>** The Partnership and Dorchester Minerals Operating LP, 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 our consolidated financial position, cash flows, or operating results.

*Operating Leases* - We have entered into an operating lease agreement in the ordinary course of our business activities. The third amendment to our office lease was signed on April 17, 2017, for a term of 129 months beginning June 1, 2018. The lease is for our office space at 3838 Oak Lawn Avenue, Suite 300, Dallas, Texas, and now expires in 2029. Under the third amendment to the office lease, monthly rental payments will range from $25,000 - $30,000 and the Partnership will receive a tenant improvement allowance of approximately $700,000. The Partnership recognizes a deferred rent liability for the rent escalations when the amount of straight-line rent exceeds the lease payments, and reduces the deferred rent liability when the lease payments exceed the straight-line rent expense. For the tenant improvement allowance, the Partnership will record a deferred rent liability and will amortize the deferred rent over the lease term as a reduction to rent expense once in use.

3 **Acquisition for Common Units:** On June 30, 2017, pursuant to a Contribution, Exchange and Purchase Agreement with DSD Royalty, LLC, a Texas limited liability company ("DSD"), the Partnership acquired producing and nonproducing royalty and mineral interests located in the Midland Basin in exchange for consideration valued at approximately $23,183,000, half in cash (the "Cash Consideration") and half in common units representing limited partner interests in the Partnership ("Common Units"), based on a price of $14.98 per Common Unit (calculated based on the average closing price of Common Units during the period beginning 15 trading days immediately prior to the closing date and ending two trading days prior to the closing date) (the "DSD Agreement"). Prior to the closing of the DSD Agreement, the Partnership entered into a Participation Agreement with certain officers of the Partnership and entities affiliated with certain officers and directors of the Partnership (the "Participants"), pursuant to which the Partnership agreed to assign an undivided 50% interest in its rights under the DSD Agreement to the Participants in exchange for the Participants' assumption of the obligation to pay the Cash Consideration on behalf of the Partnership (the "Participation Agreement"). On June 30, 2017, in connection with the closing of the DSD Agreement, the Participants contributed to the Partnership their respective assets received pursuant to the Participation Agreement in exchange for common units of the Partnership based on a price of $14.98 per Common Unit (calculated in the same manner as the price of Common Units issued pursuant to the DSD Agreement) pursuant to Contribution and Exchange Agreements with the Partnership (the "Participant Contribution Agreements"). In accordance with the transactions contemplated by the DSD Agreement and the Participant Contribution Agreements, the Partnership issued to DSD and the Participants an aggregate of 1,604,343 Common Units pursuant to the Partnership's registration statements on Form S-4. After the issuance, 6,395,657 Common Units remain available under the Partnership's registration statements on Form S-4.

4 **Distributions to Holders of Common Units:** Unitholder cash distributions per common unit since 2015 have been:

| | Per Unit Amount | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| First quarter | $0.306700 | $0.147417 | $0.306553 |
| Second quarter | $0.322965 | $0.257977 | $0.167430 |
| Third quarter | $0.284650 | $0.252224 | $0.194234 |
| Fourth quarter | | $0.241475 | $0.199076 |

Distributions beginning with the second quarter of 2017 were paid on 32,279,774 units; previous distributions set forth above were paid on 30,675,431 units. The third quarter 2017 distribution will be paid on November 9, 2017. Fourth quarter distributions shown above are paid in the first calendar quarter of the following year. Our partnership agreement requires the fourth quarter cash distribution to be paid by February 14, 2018.

**5** **New Accounting Pronouncements:** In May 2014, the FASB issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The guidance requires entities to recognize revenue using the following five-step model: identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract, and recognize revenue as the entity satisfies each performance obligation. Adoption of this standard could result in retrospective application, either in the form of recasting all prior periods presented or a cumulative adjustment to equity in the period of adoption. The company plans to adopt this standard using the modified retrospective method upon its effective date. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017.

Our Partnership's revenues are substantially attributable to oil and gas sales. Based on substantial completion of review of our contracts, we believe the timing and presentation of revenues under ASU 2014-09 will be materially consistent with our current revenue recognition policy as described above. The Partnership will continue to monitor specific developments for our industry as it relates to ASU 2014-09.

In February 2016, the FASB issued ASU 2016-02, which requires lessees to record most leases on the balance sheet. Under the new guidance, lease classification as either a finance lease or an operating lease will determine how lease-related revenue and expense are recognized. The guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company has lease commitments of approximately $3 million that we believe would be subject to capitalization under ASU 2016-02. The lease obligations that will be in place upon adoption of ASU 2016-02 may be significantly different than our current obligations. Accordingly, at this time we cannot estimate the amount that will be capitalized when this standard is adopted.

## 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 that costs, including budgeted capital expenditures, 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 the 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.

Minerals NPI production volumes and prices are within the consolidated financial statements in accordance with U.S. GAAP. Our financial statements will continue to reflect such information even if the NPI is in temporary deficit due to capital expenditures.

As of September 30, 2017, the Minerals NPI was in a surplus position and had outstanding capital commitments equaling cash on hand of $7,400,000.

**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, 2017 as compared to Three and Nine Months Ended September 30, 2016***

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, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| Accrual basis sales volumes: | 2017 | 2016 | 2017 | 2016 |
| Royalty properties gas sales (mmcf) | 967 | 775 | 2,681 | 2,461 |
| Royalty properties oil sales (mbbls) | 207 | 163 | 569 | 451 |
| NPI gas sales (mmcf) | 631 | 599 | 1,799 | 1,996 |
| NPI oil sales (mbbls) | 60 | 84 | 200 | 307 |
| Accrual basis weighted average sales price: | | | | |
| Royalty properties gas sales ($/mcf) | $ 2.63 | $ 2.42 | $ 2.94 | $ 1.94 |
| Royalty properties oil sales ($/bbl) | $ 43.32 | $ 38.72 | $ 43.46 | $ 35.44 |
| NPI gas sales ($/mcf) | $ 2.34 | $ 2.33 | $ 2.62 | $ 2.07 |
| NPI oil sales ($/bbl) | $ 41.51 | $ 36.10 | $ 40.30 | $ 33.66 |

Both oil and natural gas sales price changes reflected in the table above resulted from changing market conditions.

Oil sales volumes attributable to our Royalty Properties during the third quarter increased 27% from 163 mbbls in 2016 to 207 mbbls in the same period of 2017. Oil sales volumes attributable to the first nine months of 2016 increased 26% from 451 mbbls to 569 mbbls in the same period of 2017. The increase in volumes during the third quarter and first nine months of 2017 compared to the same periods of 2016 is mainly a result of increased Permian Basin production from new wells. Natural gas sales volumes attributable to our Royalty Properties during the third quarter increased 25% from 775 mmcf in 2016 to 967 mmcf in the same period of 2017. Natural gas sales volumes during the first nine months increased 9% from 2,461 mmcf in 2016 to 2,681 mmcf in the same period of 2017. The increase in volumes during the third quarter and first nine months of 2017 compared to the same periods of 2016 is mainly a result of increased production in the Permian Basin partially offset by decreased production in the Fayetteville Shale play.

Oil sales volumes attributable to our NPIs during the third quarter and first nine months of 2016 were 84 mbbls and 307 mbbls, respectively, resulting in decreases of 29% and 35% to 60 mbbls and 200 mbbls, respectively, during the same periods of 2017. The decrease in oil sales volumes is mainly due to natural reservoir declines. Natural gas sales volumes attributable to our NPIs during the third quarter increased 5% from 599 mmcf in 2016 to 631 mmcf in the same period of 2017 due to a higher number of suspense releases in 2017. During the first nine months of 2017, NPI natural gas volumes decreased 10% from 1,996 mmcf in 2016 to 1,799 mmcf in the same period of 2017. The decrease in gas sales volumes is mainly due to natural reservoir declines in addition to the lower amount of suspense releases in the first quarter of 2017 as compared to the first quarter of 2016.

Our third quarter net operating revenues increased 17% from $10,679,000 during 2016 to $12,480,000 during the same period of 2017. Current quarter increase in royalty revenues is primarily due to higher oil and natural gas prices, partially offset by a decrease in both net profits interests income and lease bonus income versus the prior year. Our first nine months net operating revenues increased 41% from $26,814,000 during 2016 to $37,760,000 during the same period of 2017. These increases are primarily a result of an increase in royalty revenues resulting from higher oil and natural gas prices and sales volumes.

Third quarter operating costs and expenses increased 46% from $902,000 during 2016 to $1,320,000 during the same period of 2017. Our first nine months operating costs increased 54% from $2,180,000 during 2016 to $3,358,000 during the same period of 2017. The increases in both periods are primarily a result of higher production taxes due to higher oil and natural gas sales prices.

General and administrative expenses of $1,050,000 during the third quarter of 2016 increased 9% to $1,141,000 during the same period of 2017 primarily as a result of costs related to our office remodel. General and administrative expenses of $3,967,000 during the first nine months of 2016 decreased 5% compared to $3,764,000 during the same period of 2017. The decrease is primarily due to lower information technology costs and lower legal costs associated with royalty litigation partially offset by increased costs related to our office remodel as compared to the same period of 2016.

Depletion and amortization costs of $2,080,000 during the third quarter of 2016 increased 34% to $2,795,000 during the same period of 2017 due to additional depletion from recently acquired mineral and royalty interests. Depletion and amortization costs of $6,571,000 during the first nine months of 2016 decreased 2% compared to $6,443,000 during the same period of 2017. We adjust our depletion rate each quarter for significant changes in our estimates of oil and natural gas reserves.

Third quarter net income allocable to common units increased 8% from $6,417,000 during 2016 to $6,951,000 during the same period of 2017 mainly due to higher royalty income. Our first nine months net income allocable to common units increased by 71% from $13,600,000 compared to $23,292,000 during the same period of 2017. The increase is mainly due to higher royalty income due to higher oil and natural gas prices and sales volumes.

Net cash provided by operating activities increased 45% from $21,563,000 during the first nine months of 2016 to $31,274,000 during the same period of 2017. The change is mainly driven by higher oil and natural gas sales prices. Net cash provided by investing activities increased from $0 to $331,000 mainly due to the cash contributed with the acquisition of royalty interests.

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 third quarter of 2017 totaled approximately $10,000,000. These receipts generally reflect oil sales during June 2017 through August 2017 and natural gas sales during May 2017 through July 2017. The weighted average indicated prices for oil and natural gas sales received during the 2017 third quarter attributable to the Royalty Properties were $41.36/bbl and $2.75/mcf, respectively.

Cash receipts attributable to our NPIs during the third quarter of 2017 totaled approximately $1,100,000. These receipts generally reflect oil and natural gas sales from the properties underlying the NPIs during May 2017 through July 2017. The weighted average indicated prices for oil and natural gas sales received during the 2017 third quarter attributable to our NPIs were $38.89/bbl and $2.75/mcf, respectively.

On June 28, 2017, the Partnership executed a definitive agreement to acquire producing and nonproducing mineral and royalty interests located in Glasscock, Howard, Martin, Midland, Reagan and Upton Counties, Texas. The properties consist of 1,850 net royalty acres across 22,400 gross surface acres. Approximately 75% of the total net royalty acres are located in the northwestern quarter of Reagan County and substantially overlap with the Partnership's existing position.

The transaction was consummated on June 30, 2017 and was structured as a non-taxable contribution and exchange. At the closing, in addition to conveying their interests to the Partnership, the contributing parties delivered funds in an amount equal to their cash receipts during the period from April 1, 2017 through June 30, 2017 and attributable to production on the subject properties on or after September 1, 2016, amounting to approximately $614,000, and the Partnership issued an aggregate of 1,604,343 common units of the Partnership to the contributing parties.

***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 to the Partnership in accordance with our partnership agreement. Because 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. Because 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 4 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***

The operating partnership continues to assess the opportunity to increase production based on prevailing market conditions 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.

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 $11,557,000 at September 30, 2017 and $8,212,000 at December 31, 2016.

**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, 2017 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 2. ISSUER PURCHASES OF EQUITY SECURITIES**

| Period | (a) Total Number of Units Purchased | (b) Average Price Paid per Unit | (c) Total Number of Units Purchased as Part of Publicly Announced Plans or Programs | (d) Maximum Number of Units that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| Month #1 (July 1, 2017 – July 31, 2017) | - | N/A | - | 102,149 (1) |
| Month #2 (August 1, 2017 – August 31, 2017) | - | N/A | - | 102,149 (1) |
| Month #3 (September 1, 2017 – September 31, 2017) | 18,900(2) | $14.48 | 18,900 | 83,249 (1) |
| **Total** | 18,900(2) | $14.48 | 18,900 | 83,249 (1) |

(1) The number of common units that the operating partnership may grant under the Dorchester Minerals Operating LP Equity Incentive Program, which was approved by our common unitholders on May 20, 2015 (the "**Equity Incentive Program**"), each fiscal year may not exceed 0.333% of the number of common units outstanding at the beginning of the fiscal year. In 2017, the maximum number of common units that could be granted under the Equity Incentive Program is 102,149 common units.

(2) Open-market purchases by Dorchester Minerals Operating LP, an affiliate of the Partnership, pursuant to a Rule 10b5-1 plan adopted on August 9, 2017 for the purpose of satisfying equity awards to be granted pursuant to the Equity Incentive Program.

**Item 6. 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

**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 3, 2017 | Chief Executive Officer |
| | By: /s/ Leslie Moriyama |
| | Leslie Moriyama |
| Date: November 3, 2017 | Chief Financial Officer |

15