DORCHESTER MINERALS LP
Form 10-Q
August 07, 2007

**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**Washington, DC. 20549**

**FORM 10-Q**

[X] QUARTERLY REPORT UNDER SECTION 13 or 15 (d)
OF THE SECURITIES EXCHANGE ACT OF 1934

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

For the transition period from __________ to __________

For the Quarterly Period Ended **June 30, 2007** 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 [X] No [ ]

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

| | | |
|---|---|---|
| Large accelerated filer [ ] | Accelerated filer [X] | Non-accelerated filer [ ] |

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

As of August 6, 2007, 28,240,431 common units of partnership interest were outstanding.

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**DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS**

Statements included in this report which 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 “us,” “our,” “we,” and “its” are sometimes used 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 herein 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**

**ITEM 1. FINANCIAL INFORMATION**

See attached financial statements on the following pages.

**DORCHESTER MINERALS, L.P.**
**(A Delaware Limited Partnership)**

**CONDENSED BALANCE SHEETS**
**(In Thousands)**

| **ASSETS** | June 30, 2007 (unaudited) | December 31, 2006 |
|---|---|---|
| Current assets: | | |
| Cash and cash equivalents | $ 14,537 | $ 13,927 |
| Trade receivables | 6,557 | 6,088 |
| Net profits interests receivable - related party | 5,149 | 4,126 |
| Current portion of note receivable - related party | 29 | 50 |
| Prepaid expenses | 25 | - |
| Total current assets | 26,297 | 24,191 |
| | | |
| Note receivable - related party less current portion | - | 5 |
| Other non-current assets | 19 | 19 |
| Total | 19 | 24 |
| | | |
| Property and leasehold improvements - at cost: | | |
| Oil and natural gas properties (full cost method): | 291,875 | 291,875 |
| Less accumulated full cost depletion | 155,733 | 148,064 |
| Total | 136,142 | 143,811 |
| | | |
| Leasehold improvements | 512 | 512 |
| Less accumulated amortization | 134 | 109 |
| Total | 378 | 403 |
| | | |
| Net property and leasehold improvements | 136,520 | 144,214 |
| | | |
| Total assets | $ 162,836 | $ 168,429 |
| | | |
| **LIABILITIES AND PARTNERSHIP CAPITAL** | | |
| | | |
| Current liabilities: | | |
| Accounts payable and other current liabilities | $ 849 | $ 303 |
| Current portion of deferred rent incentive | 39 | 39 |
| Total current liabilities | 888 | 342 |

| | | |
|---|---|---|
| Deferred rent incentive less current portion | 267 | 287 |
| Total liabilities | 1,155 | 629 |
| | | |
| Commitments and contingencies | | |
| | | |
| Partnership capital: | | |
| General partner | 6,613 | 6,797 |
| Unitholders | 155,068 | 161,003 |
| Total partnership capital | 161,681 | 167,800 |
| | | |
| Total liabilities and partnership capital | $ 162,836 | $ 168,429 |

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

**DORCHESTER MINERALS, L.P.**
**(A Delaware Limited Partnership)**

**CONDENSED STATEMENTS OF OPERATIONS**
**(In Thousands except Earnings per Unit)**
**(Unaudited)**

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| Operating revenues: | | | | |
| Royalties | $ 11,113 | $ 11,817 | $ 20,782 | $ 23,764 |
| Net profits interests | 6,257 | 5,322 | 11,201 | 11,878 |
| Lease bonus | 224 | 5,972 | 317 | 6,736 |
| Other | 19 | 17 | 27 | 29 |
| Total operating revenues | 17,613 | 23,128 | 32,327 | 42,407 |
| Costs and expenses: | | | | |
| Operating, including production taxes | 1,023 | 969 | 1,991 | 1,819 |
| Depletion and amortization | 3,873 | 4,813 | 7,694 | 9,521 |
| General and administrative expenses | 767 | 751 | 1,710 | 1,604 |
| Total costs and expenses | 5,663 | 6,533 | 11,395 | 12,944 |
| Operating income | 11,950 | 16,595 | 20,932 | 29,463 |
| Other income, net | 132 | 194 | 273 | 386 |
| Net earnings | $ 12,082 | $ 16,789 | $ 21,205 | $ 29,849 |
| Allocation of net earnings: | | | | |
| General partner | $ 341 | $ 547 | $ 601 | $ 925 |
| Unitholders | $ 11,741 | $ 16,242 | $ 20,604 | $ 28,924 |
| Net earnings per common unit (basic and diluted) | $ 0.42 | $ 0.58 | $ 0.73 | $ 1.02 |
| Weighted average common units outstanding | 28,240 | 28,240 | 28,240 | 28,240 |

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

**DORCHESTER MINERALS, L.P.**
**(A Delaware Limited Partnership)**

**CONDENSED STATEMENTS OF CASH FLOWS**
**(In Thousands)**
**(Unaudited)**

| | Six Months Ended June 30, 2007 | Six Months Ended June 30, 2006 |
|---|---|---|
| Net cash provided by operating activities | $ 27,908 | $ 44,511 |
| Cash flows provided by investing activities: | | |
| Proceeds from related party note receivable | 26 | 26 |
| Total cash flows provided by investing activities | 26 | 26 |
| Cash flows used in financing activities: | | |
| Distributions paid to general partner and unitholders | (27,324) | (44,567) |
| Increase (decrease) in cash and cash equivalents | 610 | (30) |
| Cash and cash equivalents at January 1, | 13,927 | 23,389 |
| Cash and cash equivalents at June 30, | $ 14,537 | $ 23,359 |

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

**DORCHESTER MINERALS, L.P.**
(A Delaware Limited Partnership)

**NOTES TO THE CONDENSED 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 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 applicable to holders of our common units by the weighted average number of units outstanding. Certain amounts in the 2006 financial statements have been reclassified to conform with the 2007 presentation. Such reclassifications did not impact net income, total assets, or total liabilities.

2. **Contingencies:** In January 2002, some individuals and an association called Rural Residents for Natural Gas Rights sued Dorchester Hugoton, Ltd., along with several other operators in Texas County, Oklahoma. Dorchester Minerals Operating LP, the operating partnership now owns and operates the properties formerly owned by Dorchester Hugoton. These properties contribute a major portion of the Net Profits Interests amounts paid to us. The plaintiffs consist primarily of Texas County, Oklahoma residents who, in residences located on leases use natural gas from gas wells located on the same leases, at their own risk, free of cost. The plaintiffs seek declaration that their domestic gas use is not limited to stoves and inside lights and is not limited to a principal dwelling as provided in the oil and gas leases entered into in the 1930s to the 1950s. Plaintiffs' claims against defendants include failure to prudently operate wells, violation of rights to free domestic gas, and fraud. Plaintiffs also seek certification of class action against defendants. On October 1, 2004, the plaintiffs severed claims against the operating partnership regarding royalty underpayments. On April 9, 2007, plaintiffs, for immaterial costs, dismissed with prejudice all claims against the operating partnership regarding domestic gas use. The operating partnership believes plaintiffs' remaining claim regarding royalty underpayments is completely without merit. An adverse decision could reduce amounts we receive from the Net Profits Interests.

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 financial position or operating results.

3. **Distributions to Holders of Common Units:** Since commencing operations on January 31, 2003, unitholder cash distributions per common unit have been:

| | Per Unit Amount | | | | |
|---|---|---|---|---|---|
| | 2003 | 2004 | 2005 | 2006 | 2007 |
| First Quarter | $0.206469 | $0.415634 | $0.481242 | $0.729852 | $0.461146 |
| Second Quarter | $0.458087 | $0.415315 | $0.514542 | $0.778120 | $0.473745 |
| Third Quarter | $0.422674 | $0.476196 | $0.577287 | $0.516082 | |
| Fourth Quarter | $0.391066 | $0.426076 | $0.805543 | $0.478596 | |

Distributions beginning with the third quarter of 2004 were paid on 28,240,431 units; previous distributions were paid on 27,040,431 units.  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 November 15, 2007.

## ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

**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 573 counties and parishes in 25 states.

Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner, holds working interests properties and a minor portion of mineral and royalty interest properties. We refer to Dorchester Minerals Operating LP as the "operating partnership." We directly and indirectly own a 96.97% net profits overriding royalty interest in property groups primarily made up of the three NPI's created when we commenced operations and the 2003-2006 NPI. We refer to our net profits overriding royalty interest in these property groups as the Net Profits Interests. We currently receive monthly payments equaling 96.97% of the preceding month's net profits actually realized by the operating partnership from three of the property groups.

In accordance with our partnership agreement we have the continuing right and obligation to create additional Net Profits Interests by transferring properties to the operating partnership subject to the reservation of a Net Profits Interest identical to the Net Profits Interests created when we commenced operations in 2003. The purpose of such Net Profits Interests is to avoid the Partnership's participation as a working interest or other cost expense-bearing owner that could result in unrelated business taxable income. Net profits interest payments are not considered unrelated business taxable income for tax purposes. One such Net Profits Interest was created for each of calendar years 2003 through 2006 by transferring various properties to the operating partnership subject to a Net Profits Interest. These interests were subsequently combined and we currently refer to them as the 2003-2006 NPI. As of June 30, 2007, cumulative operating and development costs presented in the following table, which include amounts equivalent to an interest charge, exceeded cumulative revenues of the 2003-2006 NPI, resulting in a cumulative deficit. All cumulative deficits (which represent cumulative excess of operating and development costs over revenue received) are borne 100% by our General Partner until the 2003-2006 NPI recovers the deficit amount. Once in profit status, we will receive the Net Profits Interest payment attributable to these properties. Our financial statements do not reflect activity attributable to properties subject to Net Profits Interests that are in a deficit status. Consequently, Net Profits Interest payments, and production sales volumes and prices set forth in other portions of this quarterly report do not reflect amounts attributable to the 2003-2006 NPI.

The following table sets forth cash receipts and disbursements attributable to the 2003-2006 Net Profits Interest:

2003-2006 Net Profits Interest Cash Basis Results
(in Thousands)

| | Cumulative Total at December 31, 2006 | Six Months Ended June 30, 2007 | Cumulative Total at June 30, 2007 |
|---|---|---|---|
| Cash received for revenue | $ 4,945 | $ 1,327 | $ 6,272 |
| Cash paid for operating costs | (852) | (220) | (1,072) |
| Cash paid for development costs | (4,311) | (1,289) | (5,600) |
| Net cash (paid) received | $ (218) | $ (182) | $ (400) |
| | $ (218) | $ (400) | $ (400) |

| |
|---|
| Cumulative NPI Deficit |

The development costs pertain to more properties than the properties producing revenue due to timing differences between operating partnership expenditures and oil and gas production and payments to the operating partnership.  Amounts in the above table reflect the operating partnership's ownership of the subject properties.  Net Profits Interest payments to us, if any, will equal 96.97% of the cumulative net profits actually received by the operating partnership attributable to subject properties.  The above financial information attributable to the 2003-2006 NPI may not be indicative of future results of the 2003-2006 NPI and may not indicate when the deficit status may end and when Net Profits Interest payments may begin from the 2003-2006 NPI.

**Commodity Price Risks**

Our profitability is affected by volatility in prevailing oil and natural gas prices. Oil and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for oil and natural gas in the market and general market volatility.

**Results of Operations**

***Three and Six Months Ended June 30, 2007 as compared to Three and Six Months Ended June 30, 2006***

Normally, our period-to-period changes in net earnings 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 | | | Six Months Ended | |
|---|---|---|---|---|---|
| | June 30, | | March 31, | June 30, | |
| **Accrual Basis Sales Volumes:** | **2007** | **2006** | **2007** | **2007** | **2006** |
| Royalty Properties Gas Sales (mmcf) | 838 | 1,014 | 858 | 1,696 | 1,979 |
| Royalty Properties Oil Sales (mbbls) | 79 | 84 | 74 | 153 | 169 |
| Net Profits Interests Gas Sales (mmcf) | 1,035 | 1,140 | 1,016 | 2,051 | 2,266 |
| Net Profits Interests Oil Sales (mbbls) | 4 | 4 | 4 | 8 | 7 |
| | | | | | |
| **Accrual Basis Weighted Average Sales Price:** | | | | | |
| Royalty Properties Gas Sales ($/mcf) | $ 7.71 | $ 6.18 | $ 6.60 | $ 7.15 | $ 6.77 |
| Royalty Properties Oil Sales ($/bbl) | $ 59.13 | $ 65.86 | $ 53.87 | $ 56.58 | $ 61.25 |
| Net Profits Interests Gas Sales ($/mcf) | $ 7.82 | $ 5.80 | $ 6.74 | $ 7.28 | $ 6.61 |
| Net Profits Interests Oil Sales ($/bbl) | $ 56.62 | $ 53.51 | $ 46.41 | $ 51.66 | $ 50.61 |
| | | | | | |
| Accrual Basis Production Costs Deducted under the Net Profits Interests ($/mcfe) (1) | $ 2.06 | $ 1.36 | $ 2.08 | $ 2.07 | $ 1.55 |

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

Oil sales volumes attributable to our Royalty Properties during the second quarter decreased 6.0% from 84 mbbls in 2006 to 79 mbbls in 2007. Oil sales volumes attributable to our Royalty Properties during the first six months decreased 9.5% from 169 mbbls in 2006 to 153 mbbls in 2007. Natural gas sales volumes attributable to our Royalty Properties during the second quarter decreased 17.4% from 1,014 mmcf in 2006 to 838 mmcf in 2007. Natural gas sales volumes attributable to our Royalty Properties during the first six months decreased 14.3% from 1,979 in 2006 to 1,696 mmcf in 2007. The decreases in oil and natural gas sales volumes were primarily attributable to wells completed in the T-Patch Field in early 2006. As previously reported, these wells have exhibited significant production declines after initially producing at anomalously high rates. In addition, first sales from recent completions in this Field and the Jeffress Field occurred in late May and June 2007. Cash receipts during the quarter attributable to these new wells were insignificant. In addition, Royalty Properties located in South Texas and the Mid-Continent experienced weather-related production disruptions throughout the first quarter and portions of the second quarter.

Oil sales volumes attributable to our Net Profits Interests during the second quarter and first six months of 2007 were virtually unchanged when compared to the same periods of 2006. Natural gas sales volumes attributable to our Net Profits Interests during the second quarter and first six months of 2007 decreased from the same periods of 2006. Second quarter sales of 1,035 mmcf during 2007 were 9.2% less than 1,140 mmcf during 2006. First six month sales of 2,051 mmcf during 2007 were 9.5% less than 2,266 mmcf during 2006. The natural gas sales volume decreases were a result of natural reservoir decline, scheduled equipment and facility maintenance and January weather-related production disruptions. Production sales volumes and prices from the 2003-2006 NPI are excluded from the above table. See “Overview” above.

Weighted average oil sales prices attributable to our interest in Royalty Properties decreased 10.2% from $65.86/bbl during the second quarter of 2006 to $59.13/bbl during the second quarter of 2007 and 7.6% from $61.25/bbl during the first six months of 2006 to $56.58/bbl during the first six months of 2007. Second quarter weighted average natural gas sales prices from Royalty Properties increased 24.8% from $6.18/mcf during 2006 to $7.71/mcf during 2007. The six months ended June 30 weighted average partnership natural gas sales prices increased 5.6% from $6.77/mcf during 2006 to $7.15/mcf during 2007. Both oil and natural gas price changes resulted from changing market conditions.

Second quarter weighted average oil sales prices from the Net Profits Interests' properties increased 5.8% from $53.51/bbl in 2006 to $56.62/bbl in 2007. The first six months' Net Profits Interests' oil sales prices increased 2.1% from $50.61/bbl in 2006 to $51.66/bbl in 2007. Weighted average natural gas sales prices attributable to the Net Profits Interests increased during the second quarter and first six months of 2007 compared to the same periods of 2006. Second quarter natural gas sales prices of $7.82/mcf in 2007 were 34.8% greater than $5.80/mcf in 2006. The six months ended June 30, 2007 natural gas prices increased 10.1% to $7.28/mcf from $6.61/mcf in the same period of 2006. Changing market conditions resulted in increased oil prices. Natural gas sales price increases resulted from changing market conditions plus abnormal natural gas liquid payments.

In an effort to provide the reader with information concerning prices of oil and 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 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 Net Profits Interests during the 2007 second quarter totaled $4,978,000. These receipts generally reflect oil and gas sales from the properties underlying the Net Profits Interests during February through April 2007. The weighted average indicated prices for oil and gas sales during the 2007 second quarter attributable to the Net Profits Interests were $50.75/bbl and $6.92/mcf, respectively.

Cash receipts attributable to our Royalty Properties during the 2007 second quarter totaled $9,956,000. These receipts generally reflect oil sales during March through May 2007 and gas sales during February through April 2007. The weighted average indicated prices for oil and gas sales during the 2007 second quarter attributable to the Royalty Properties were $57.21/bbl and $7.16/mcf, respectively.

Our second quarter net operating revenues decreased 23.8% from $23,128,000 during 2006 to $17,613,000 during 2007. Net operating revenues for the first six months of 2007 decreased 23.8% from $42,407,000 during 2006 to $32,327,000 during 2007. Both the quarterly and six month decreases resulted primarily from decreased lease bonus revenues. First quarter 2006 net operating revenues included a non-refundable lease bonus payment of $616,000 related to our Arkansas lease transactions and the second quarter of 2006 net operating revenues included $5,535,000 additional Arkansas lease bonus payment plus other lease bonuses of $717,000.

Costs and expenses decreased 13.3% from $6,533,000 during the second quarter of 2006 to $5,663,000 during the second quarter of 2007, while six month ended June 30 costs and expenses decreased 12.0% from $12,944,000 during 2006 to $11,395,000 during 2007. Such decreases primarily resulted from decreased depletion and amortization, offset by increased general and administrative expenses and ad valorem taxes associated with increased oil and gas ad valorem valuations.

Depletion and amortization decreased 19.5% during the second quarter ended June 30, 2007 and 19.2% during the six months ended June 30, 2007 when compared to the same periods of 2006. The decreases from $4,813,000 and $9,521,000 during the second quarter and six months ended June 30, 2006 respectively, to $3,873,000 and $7,694,000 during the same periods of 2007 respectively, resulted from a lower depletable base due to effects of previous depletion and upward revisions in oil and gas reserve estimates at 2006 year end.

We received cash payments in the amount of $221,000 from various sources during the second quarter of 2007 including lease bonuses attributable to 37 consummated leases and pooling elections located in five counties and parishes in three states. The consummated leases reflected royalty terms ranging up to 30% and lease bonuses ranging up to $300/acre.

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We received division orders, or otherwise identified, 72 new wells completed on our Royalty Properties and Net Profit Interests located in 32 counties and parishes in eight states during the second quarter of 2007. The operating partnership elected to participate in nine wells to be drilled on our Net Profits Interests located in four counties in three states. Selected new wells and the royalty interests owned by us and the working and net revenue interests owned by the operating partnership are summarized in the following table. This table does not include wells drilled in the Fayetteville Shale Trend as they are detailed in a subsequent discussion and table.

| County | | | | DMLP | DMOLP | | Test Rates per day | |
|---|---|---|---|---|---|---|---|---|
| State | /Parish | Operator | Well Name | NRI(2) | WI(1) | NRI(2) | Gas, mcf | Oil, bbls |
| TX | Hidalgo | El Paso E & P Company | Coates A-36 | 6.4228% | 0.0000% | 0.0000% | 13,334 | 167 |
| TX | Starr | EOG Resources | Southwest Texas Corp #8 | 5.1208% | 0.0000% | 0.0000% | 5,169 | 136 |
| OK | Caddo | Apache Corporation | Trogdon 3-9 | 1.4063% | 0.0000% | 0.0000% | 4,737 | 1 |
| TX | Panola | Chesapeake Operating | Bill Powers A 7 | 5.5211% | 0.0000% | 0.0000% | 952 | 27 |
| AR | Conway | SEECO | Jerome Carr #1-31H | 2.1876% | 0.0000% | 0.0000% | 1,622 | 0 |
| TX | Matagorda | Deep Rock Resources | Flowers Foundation #3 | 1.7439% | 0.0000% | 0.0000% | 1,250 | 47 |
| TX | Upton | Southwest Royalties | R S Windham C #3 | 0.5859% | 0.0000% | 0.0000% | 70 | 525 |
| TX | Loving | Chaparral Energy | E O Schawe #15 | 4.1667% | 0.0000% | 0.0000% | 380 | 2 |
| TX | Hidalgo | Dan A. Hughes | Coates-Dorchester #3 | 6.2500% | 6.2500% | 4.6875% | 4,209 | 70 |
| AR | Logan | Hanna Oil & Gas | Mixon 1-21 | 0.0000% | 3.0901% | 3.0901% | 1,031 | 0 |

(1) WI means the working interest owned by the operating partnership and subject to the Net Profits Interest.

(2) NRI means the net revenue interest attributable to our royalty interest or to the operating partnership's working interest and subject to the Net Profits Interest.

FAYETTEVILLE SHALE TREND OF NORTHERN ARKANSAS- We own varying undivided perpetual mineral interests totaling 23,336/11,464 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. Thirty wells have been permitted on the lands as of July 25, 2007. Wells which have been proposed to be drilled by the operator but for which permits have not yet been issued by the Arkansas Oil & Gas Commission are not reflected in this number. Selected new wells and permitted locations and the royalty interests owned by us as well as the working and net revenue interests owned by the operating partnership are summarized in the following table.

| | | | DMLP | DMOLP | | Gas Test Rates |
|---|---|---|---|---|---|---|
| County | Operator | Well Name | NRI(2) | WI(1) | NRI(2) | Mcf per day |
| Cleburne | SEECO | Mulliniks 9-12 #1-35H | 3.516% | 5.000% | 3.750% | -- |
| Cleburne | SEECO | Mulliniks 9-12 #2-35H | 3.516% | 5.000% | 3.750% | -- |
| Cleburne | SEECO | Mulliniks 9-12 #3-35H | 3.516% | 5.000% | 3.750% | -- |

| | | | | | | |
|---|---|---|---|---|---|---|
| Conway | David Arrington | Beverly Crofford #1-14 H | 1.563% | 1.250% | 0.938% | -- |
| Conway | SEECO | Jerome Carr #1-31H | 2.207% | 3.796% | 2.847% | 1,846 |
| Conway | SEECO | Jerome Carr #2-31H | 2.207% | 3.796% | 2.847% | 3,234 |
| Conway | SEECO | McCoy 8-16 #1-1H | 6.250% | 5.000% | 3.750% | -- |
| Conway | SEECO | McCoy 8-16 #2-1H | 6.250% | 5.000% | 3.750% | -- |
| Conway | SEECO | McCoy 8-16 #3-1H | 6.250% | 5.000% | 3.750% | -- |
| Conway | SEECO | Polk 09-15 #1-30H | 5.898% | 5.561% | 4.220% | 1,614 |
| Conway | SEECO | Polk 09-15 #2-30H | 5.898% | 4.970% | 3.727% | -- |
| Pope | Penn Virginia | Brown #1-33H | 1.563% | 1.250% | 0.938% | -- |
| Pope | Penn Virginia | Tackett #1-33H | 1.563% | 1.250% | 0.938% | 287 |
| Van Buren | One TEC Oper. | Gunn #1-19H | 2.246% | 3.984% | 2.988% | -- |
| Van Buren | SEECO | Hillis #2-27H | 0.000% | 0.000% | 0.781% | 2,334 |
| Van Buren | SEECO | Hillis #3-27H | 0.000% | 6.250% | 6.250% | -- |
| Van Buren | SEECO | Hillis 1-27 | 0.000% | 6.250% | 6.250% | 880 |
| Van Buren | SEECO | Jones 10-16 #1-33H | 0.000% | 3.125% | 3.125% | 2,207 |
| Van Buren | SEECO | Jones 10-16 #2-33H | 0.000% | 3.125% | 3.125% | 2,063 |
| Van Buren | SEECO | Jones 10-16 #3-33H | 0.000% | 3.125% | 3.125% | -- |
| Van Buren | SEECO | Koone-Hillis 10-16 #1-34H27 | 0.000% | 2.377% | 2.377% | -- |
| Van Buren | SEECO | Love 10-12 #1-17H | 5.840% | 5.000% | 3.750% | -- |
| Van Buren | SEECO | Nelon 9-13 #1-26H | 0.781% | 0.000% | 0.000% | -- |
| Van Buren | SEECO | Nelon 9-13 #2-26H | 0.781% | 0.000% | 0.000% | -- |
| Van Buren | SEECO | Quattlebaum #1-32H | 0.781% | 0.000% | 0.000% | 1,717 |
| Van Buren | SEECO | Quattlebaum #2-32H | 0.781% | 0.000% | 0.000% | 1,365 |
| Van Buren | SEECO | Russell #1-33H | 0.000% | 6.250% | 6.250% | 2,928 |
| Van Buren | SEECO | Russell #2-33H | 0.000% | 6.450% | 6.420% | 844 |
| White | Chesapeake | Beals 8-7 #1-13H | 0.781% | 0.000% | 0.000% | -- |
| White | Chesapeake | Hays 8-6 #1-18H | 0.781% | 0.000% | 0.000% | -- |

(1) WI means the working interest owned by the operating partnership and subject to the Net Profits Interest.

(2) NRI means the net revenue interest attributable to our royalty interest or to the operating partnership's working interest and subject to the Net Profits Interest.

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Second quarter net earnings allocable to common units decreased 27.7% from $16,242,000 during 2006 to $11,741,000 during 2007. First six months common unit net earnings decreased 28.8% from $28,924,000 during 2006 to $20,604,000 during 2007. The 2007 decrease from second quarter 2006 net earnings is primarily a result of decreased 2007 lease bonus revenues compared to 2006 which included $6,151,000 attributable to Arkansas transactions.

Net cash provided by operating activities decreased 38.6% from $23,017,000 during the second quarter of 2006 to $14,143,000 during the second quarter of 2007. Similarly, net cash provided by operating activities for the first six months decreased 37.3% from $44,511,000 during 2006 to $27,908,000 during 2007. The principal reasons for such decreases is higher receivables in 2006 due to fourth quarter 2005 market pricing of oil and gas sales and higher 2006 lease bonus revenues primarily related to Arkansas transactions. See discussion above on net operating revenues.

**Liquidity and Capital Resources**

***Capital Resources***

Our primary sources of capital are our cash flow from the Net Profits Interests 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 prices and sales 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 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***

During February 2007 the operating partnership drilled one replacement Guymon-Hugoton well and one Council Grove formation well, both in Oklahoma. The Guymon-Hugoton replacement well increased production from 8 to 90 mcf per day. The Council Grove well was a dry hole costing approximately $280,000. Final cost of the replacement Guymon-Hugoton well is expected to be approximately $500,000.

During 2007, depending upon rig availability, the operating partnership anticipates drilling one additional well in the Oklahoma Council Grove formation. The operating partnership does not otherwise currently anticipate drilling additional wells as a working interest owner/operator in the Oklahoma or Kansas properties. Successful activities by others or other developments could prompt a reevaluation of this position. Present drilling and completion costs are estimated at $350,000 - $500,000 per well. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests.

The operating partnership anticipates continuing fracture treating in its Oklahoma properties but is unable to predict the cost as a specific engineering study is required for each fracture treatment. Previous fracture treatments in these properties have cost between $50,000 and $80,000 per well. They did not require casing repairs. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests.

The operating partnership owns and operates the wells, pipelines and gas compression and dehydration facilities located in Kansas and Oklahoma. The operating partnership anticipates gradual increases in expenses as repairs to these facilities become more frequent, and anticipates gradual increases in field operating expenses as reservoir pressure declines. 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 Net Profits Interests 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 Net Profits Interests. 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 $14,537,000 at June 30, 2007 and $13,927,000 at December 31, 2006.

**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. Oil and gas properties are evaluated using the full cost ceiling test 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 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 more significant revisions will not be necessary in the future. Significant downward revisions could result in an impairment representing a non-cash charge to earnings. In addition to the impact on 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 prices 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 royalties and net profits interests in properties operated by non-affiliated entities are particularly subjective due to 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 reasonably possible losses.

### Market Risk Related to Oil and Natural Gas Prices

Essentially all of our assets and sources of income are from the Royalties and the Net Profits Interests, 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 volatile and 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 which 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 effectively ensure that the information required to be disclosed in the reports we file with the Securities and Exchange Commission is recorded, processed, summarized and reported, within the time periods specified by the Securities and Exchange Commission.

### 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 June 30, 2007 that have materially affected, or are reasonably likely to materially affect, our internal controls subsequent to the date of their evaluation of our disclosure controls and procedures.

## PART II

**ITEM 1. LEGAL PROCEEDINGS**

See Note 2 – Contingencies, to the Financial Statements.

**ITEM 1A. RISK FACTORS**

None.

**ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS**

None.

**ITEM 3. DEFAULTS UPON SENIOR SECURITIES**

None.

**ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS**

a) We held our Annual Unitholders meeting on Wednesday, May 16, 2007 in Dallas, Texas.

b) Proxies were solicited by the Board of Managers pursuant to Regulation 14A under the Securities Exchange Act of 1934. There were no solicitations in opposition to the nominees listed in the proxy statement and all of such nominees were duly elected.

c) The only matter voted on at the meeting was the election of the three nominees to the Board of Managers. Out of 28,240,431 units issued and outstanding and entitled to vote at the meeting 26,262,441 units were present in person or by proxy. The results are as follows:

| Nominee | Votes for Election | Votes Withheld from Election | Broker Non-Votes |
|---|---|---|---|
| Buford P. Berry | 25,978,104 | 284,337 | 1,977,990 |
| Rawles Fulgham | 25,965,841 | 296,600 | 1,977,990 |
| C. W. “Bill” Russell | 26,012,600 | 249,841 | 1,977,990 |

**ITEM 5. OTHER INFORMATION**

None.

**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

/s/ William Casey McManemin
William Casey McManemin
Chief Executive Officer

Date: August 7, 2007

/s/ H.C. Allen, Jr.
H.C. Allen, Jr.
Chief Financial Officer

Date: August 7, 2007

**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 Agreement of Limited Partnership 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) |
| 3.11 | Certificate of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.12 | Agreement of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.13 | |

| | |
|---|---|
| | Certificate of Incorporation of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.13 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.14 | Bylaws of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.14 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.15 | Certificate of Limited Partnership of Dorchester Minerals Acquisition LP (incorporated by reference to Exhibit 3.15 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2004) |
| 3.16 | Agreement of Limited Partnership of Dorchester Minerals Acquisition LP (incorporated by reference to Exhibit 3.16 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004) |
| 3.17 | Certificate of Incorporation of Dorchester Minerals Acquisition GP, Inc. (incorporated by reference to Exhibit 3.17 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004) |
| 3.18 | Bylaws of Dorchester Minerals Acquisition GP, Inc. (incorporated by reference to Exhibit 3.18 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004) |
| 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) |