

DORCHESTER MINERALS LP
Form 10-Q
May 05, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2011

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
(State or other jurisdiction of
incorporation or organization)

81-0551518
(I.R.S. Employer
Identification No.)

3838 Oak Lawn Avenue, Suite 300, Dallas, Texas 75219
(Address of principal executive offices) (Zip Code)

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

None

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

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

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

Non-accelerated filer

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Large accelerated
filer

Accelerated
filer

Smaller reporting
company

(Do not check if a smaller
reporting company)

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

As of May 4, 2011, 30,675,431 common units representing limited partnership interests were outstanding.

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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 discuss 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 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 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

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)CONDENSED CONSOLIDATED BALANCE SHEETS
(In Thousands)

ASSETS	March 31, 2011 (unaudited)	December 31, 2010
Current assets:		
Cash and cash equivalents	\$13,930	\$11,253
Trade and other receivables	6,190	5,548
Net profits interests receivable - related party	1,490	3,651
Prepaid expenses	37	-
Total current assets	21,647	20,452
Other non-current assets	19	19
Total	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	344,194	344,194
Accumulated full cost depletion	(215,991)	(211,761)
Total	128,203	132,433
Leasehold improvements	512	512
Accumulated amortization	(317)	(305)
Total	195	207
Net property and leasehold improvements	128,398	132,640
Total assets	\$150,064	\$153,111
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	\$1,014	\$542
Current portion of deferred rent incentive	39	39
Total current liabilities	1,053	581
Deferred rent incentive less current portion	119	129
Total liabilities	1,172	710
Commitments and contingencies (Note 2)		

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Partnership capital:		
General partner	4,550	4,669
Unitholders	144,342	147,732
Total partnership capital	148,892	152,401
Total liabilities and partnership capital	\$150,064	\$153,111

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

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

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

	Three Months Ended March 31,	
	2011	2010
Operating revenues:		
Royalties	\$12,128	\$11,964
Net profits interests	2,079	3,185
Lease bonus	77	372
Other	5	18
Total operating revenues	14,289	15,539
Costs and expenses:		
Operating, including production taxes	1,151	1,210
Depletion and amortization	4,242	4,235
General and administrative expenses	1,156	1,170
Total costs and expenses	6,549	6,615
Operating income	7,740	8,924
Other income, net	-	2
Net earnings	\$7,740	\$8,926
Allocation of net earnings:		
General partner	\$269	\$292
Unitholders	\$7,471	\$8,634
Net earnings per common unit (basic and diluted)	\$0.24	\$0.29
Weighted average common units outstanding	30,675	29,849

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

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

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

	Year Ended March 31,	
	2011	2010
Net cash provided by operating activities	\$13,930	\$14,155
Cash flows (used in) provided by investing activities:		
Adjustment related to acquisition of natural gas properties	(4)	407
Capital expenditures	-	(34)
Total cash flows (used in) provided by investing activities	(4)	373
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(11,249)	(9,934)
Increase in cash and cash equivalents	2,677	4,594
Cash and cash equivalents at beginning of period	11,253	10,124
Cash and cash equivalents at end of period	\$13,930	\$14,718
Non-cash investing and financing activities:		
Value of units issued for natural gas properties acquired	\$-	\$17,685

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

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

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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

The condensed consolidated financial statements reflect all adjustments (consisting only of normal and recurring adjustments unless indicated otherwise) that are, in the opinion of management, necessary for the fair presentation of our financial position and operating results for the interim period. Interim period results are not necessarily indicative of the results for the calendar year. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information. Per-unit information is calculated by dividing the earnings 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 earnings or loss 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, 2010.

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

2 Contingencies: 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 regarding the use of natural gas from the wells in residences. 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 NPI amounts paid to us. On April 9, 2007, plaintiffs, for immaterial costs, dismissed with prejudice all claims against the operating partnership regarding such residential gas use. On October 4, 2004, the plaintiffs filed severed claims against the operating partnership regarding royalty underpayments, which the Texas County District Court subsequently dismissed with a grant of time to replead. On January 27, 2006, one of the original plaintiffs again sued the operating partnership for underpayment of royalty, seeking class action certification. On October 1, 2007, the Texas County District Court granted the operating partnership’s motion for summary judgment finding no royalty underpayments. Subsequently, the District Court denied the plaintiff’s motion for reconsideration, and the plaintiff filed an appeal. On March 31, 2010, the appeal decision reversed and remanded to the Texas County District Court to resolve material issues of fact. A hearing on a revised motion for summary judgment is set for June 2011. An adverse decision could reduce amounts we receive from the NPIs.

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

3 Acquisition for Units: On March 31, 2010, Dorchester Minerals, LP and a newly formed subsidiary acquired all of the outstanding partnership interests in Maecenas Minerals, LLP, a Texas limited liability partnership that owns producing and nonproducing mineral and royalty interests located in 17 states, in exchange for 835,000 common units

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of Dorchester Minerals, L.P. valued at \$17,685,000 and issued pursuant to a shelf registration statement. The Condensed Consolidated Balance Sheets presented include \$17,121,000 in property additions as well as other assets and liabilities acquired. After the issuance, 2,565,000 units remain available under the shelf registration statement.

4 Distributions to Holders of Common Units: Unitholder cash distributions per common unit since 2007 have been:

	Per Unit Amount				
	2011	2010	2009	2008	2007
First quarter	\$0.426745	\$0.449222	\$0.401205	\$0.572300	\$0.461146
Second quarter		\$0.412207	\$0.271354	\$0.769206	\$0.473745
Third quarter		\$0.471081	\$0.286968	\$0.948472	\$0.560502
Fourth quarter		\$0.354074	\$0.321540	\$0.542081	\$0.514625

Distributions beginning with the first quarter of 2010 were paid on 30,675,431 units; distributions from the second quarter of 2009 through the fourth quarter of 2009 were paid on 29,840,431 units; previous distributions above were paid on 28,240,431 units. The first quarter 2011 distribution was paid today, May 5, 2011. 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 August 15, 2011.

5 New Accounting Pronouncements: None.

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.

Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner, holds working interest properties and a minor portion of mineral and royalty interest properties. We refer to Dorchester Minerals Operating LP as the "operating partnership" or "DMOLP." We directly and indirectly own a 96.97% net profits overriding royalty interest (referred to as NPI, or NPIs) in property groups made up of four NPIs created when we commenced operations in 2003, one immaterial NPI subsequently created and currently in deficit and the Maecenas Minerals NPI created in 2010. We currently receive monthly payments equaling 96.97% of the preceding month's net profits actually realized by the operating partnership from four of the property groups. The purpose of such NPIs is to avoid the participation as a working interest or other cost-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 NPI, referred to as the Minerals NPI, has continuously had costs that exceed revenues. As of March 31, 2011, cumulative operating and development costs presented in the following table, which include amounts equivalent to an interest charge, exceeded cumulative revenues of the Minerals 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 Minerals NPI recovers the deficit amount. Once in profit status, we will receive the NPI payments attributable to these properties. Our consolidated financial statements do not reflect activity attributable to properties subject to NPIs that are in a deficit status. Consequently, NPI payments and production sales volumes and prices set forth in other portions of this quarterly report do not reflect amounts attributable to the Minerals NPI, which includes all of the operating partnership's Fayetteville Shale working interest properties in Arkansas.

The following table sets forth receipts and disbursements attributable to the Minerals NPI:

	Minerals NPI Results (in Thousands)		
	Cumulative Total at 12/31/10	Three Months Ended 3/31/11	Cumulative Total at 3/31/11
Cash received for revenue	\$ 25,525	\$ 2,407	\$ 27,932
Cash paid for operating costs	4,823	481	5,304
Cash paid for development costs	19,321	981	20,302
Budgeted capital expenditures	4,425	494	4,919
Net	\$ (3,044)	\$ 451	\$ (2,593)

The development costs pertain to more properties than the properties producing revenue due to timing differences between operating partnership expenditures and oil and natural gas production and payments to the operating partnership. The amounts reflect the operating partnership's ownership of the subject properties. NPI 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 Minerals NPI may not be indicative of future results of the Minerals NPI and may not indicate when the deficit status may end and when NPI payments may begin from the Minerals 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 along with domestic and international political economic conditions.

Results of Operations

Three Months Ended March 31, 2011 as compared to Three Months Ended March 31, 2010

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 March 31,	
	2011	2010
Accrual basis sales volumes:		
Royalty properties gas sales (mmcf)	1,342	1,247
Royalty properties oil sales (mmbbls)	78	75
NPI gas sales (mmcf)	797	832
NPI oil sales (mmbbls)	2	2
Accrual basis weighted average sales price:		
Royalty properties gas sales (\$/mcf)	\$ 3.95	\$ 5.14
Royalty properties oil sales (\$/bbl)	\$ 87.52	\$ 74.44
NPI gas sales (\$/mcf)	\$ 4.16	\$ 5.23
NPI oil sales (\$/bbl)	\$ 85.46	\$ 70.33
Accrual basis production costs deducted under the NPIs (\$/mcf) (1)	\$ 1.85	\$ 1.68

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

Oil sales volumes attributable to our Royalty Properties during first quarter 2011 were up slightly compared to the first quarter of 2010. Natural gas sales volumes attributable to our Royalty Properties during first quarter 2011 increased 7.6% from 1,247 mmcf in 2010 to 1,342 mmcf in 2011. The increases in oil and natural gas sales volumes were due to the acquisition of Maecenas Minerals LLP on March 31, 2010, activity in the Fayetteville Shale trend of Arkansas, and continued development activities on the Royalty Properties.

Oil sales volumes attributable to our NPIs during first quarter 2011 were about the same as first quarter 2010. Natural gas sales volumes attributable to our NPIs during first quarter 2011 decreased 4.2% from 832 mmcf during first quarter 2010 to 797 mmcf during first quarter 2011. The natural gas sales volume decrease was a result of natural reservoir decline. Production sales volumes and prices from the Minerals NPI are excluded from the above table. See "Overview" above.

The weighted average oil sales prices attributable to our interest in Royalty Properties increased 17.6% from \$74.44/bbl during first quarter 2010 to \$87.52/bbl during first quarter 2011. First quarter weighted average natural gas sales prices from Royalty Properties decreased 23.2% from \$5.14/mcf during 2010 to \$3.95/mcf during 2011. Both oil and natural gas price changes resulted from changing market conditions.

First quarter weighted average oil sales prices from the NPIs increased 21.5% from \$70.33/bbl in 2010 to \$85.46/bbl in 2011. Weighted average natural gas sales prices attributable to the NPIs decreased 20.5% from \$5.23/mcf during first quarter 2010 to \$4.16/mcf during first quarter 2011. Both oil and natural gas price changes resulted from changing market conditions.

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Our first quarter total operating revenues decreased 8.0% from \$15,539,000 during 2010 to \$14,289,000 during 2011 as a result of changing oil and natural gas sales prices, along with reduced lease bonus income.

Costs and expenses of \$6,549,000 during first quarter 2011 were essentially the same as \$6,615,000 during first quarter 2010.

Depletion and amortization was about the same at \$4,235,000 during first quarter 2010 compared to \$4,242,000 during first quarter 2011.

First quarter net earnings allocable to common units decreased 13.5% from \$8,634,000 during 2010 to \$7,471,000 during 2011 primarily due to reduced natural gas sales prices, partially offset by increased oil prices.

Net cash provided by operating activities decreased slightly from \$14,155,000 during first quarter 2010 to \$13,930,000 during first quarter 2011 primarily due to changes in oil and natural gas sales prices.

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 first quarter 2011 totaled approximately \$10,700,000. These receipts generally reflect oil sales during December 2010 through February 2011 and natural gas sales during November 2010 through January 2011. The weighted average indicated prices for oil and natural gas sales during first quarter 2011 attributable to the Royalty Properties were \$84.02/bbl and \$3.73/mcf, respectively.

Cash receipts attributable to our NPIs during first quarter 2011 totaled approximately \$4,200,000. These receipts reflect oil and natural gas sales from the properties underlying the NPIs generally during November 2010 through January 2011. The weighted average indicated prices received during first quarter 2011 for oil and natural gas sales were \$76.25/bbl and \$7.16/mcf, respectively. The natural gas weighted average indicated price for the quarter was increased by \$3.17/mcf due to the receipt of a natural gas liquids payment of \$2,400,000 for 2010 production. The natural gas liquids payment is based on an Oklahoma Guymon-Hugoton field 1994 gas delivery agreement that is in effect through 2015. Under the terms of the agreement, when the market price of natural gas liquids increases sufficiently disproportionately to natural gas market prices, the operating partnership receives a portion of that increase in an annual payment based on calendar year data. In the event the evaluation at the end of the annual contract period shows the payment to be determinable and collectable, the revenue is accrued.

We received cash payments of approximately \$125,000 from various sources during the first quarter of 2011 attributable to, among other things, seven consummated leases and pooling elections located in six counties and parishes in two states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to \$2,000/acre.

We received division orders for, or otherwise identified, 122 new wells completed on our Royalty Properties and NPIs located in 38 counties and parishes in five states during the first quarter of 2011. The operating partnership elected to participate during the quarter in 13 wells to be drilled on our NPIs located in three counties in Arkansas.

APPALACHIAN BASIN – We own varying undivided perpetual mineral interests in approximately 31,000/24,000 gross/net acres in 19 counties in southern New York and northern Pennsylvania. Approximately 75% of these net acres are located in eastern Allegany and western Steuben Counties, New York, an area which some industry press reports suggest may be prospective for gas production from unconventional reservoirs, including the Marcellus Shale. The New York State Department of Environmental Conservation has restricted permitting in the Marcellus shale pending a regulatory review of high-volume hydraulic fracturing practices. Development of these natural gas resources will be limited until this regulatory issue has been resolved. We continue to monitor industry activity and encourage dialogue with industry participants to determine the proper course of action regarding our interests in this area.

BARNETT SHALE – We own producing and nonproducing mineral and royalty interests located in Tarrant County, Texas. The properties consist of varying undivided mineral and overriding royalty interests in six tracts totaling approximately 1,820 acres in what is commonly referred to as the Core Area of the Barnett Shale Trend. All of the mineral interests were leased in 2003 to a predecessor of Chesapeake Energy Corporation, the current operator of and majority working interest owner in the properties. Approximately 577 acres of the subject lands are pooled into six units totaling 1,800 acres; approximately 1,129 acres are developed on a lease basis and the remaining lands are leased

but not pooled or drilled upon. As of March 31, 2011, 41 wells were drilled from 11 padsites located on or adjacent to the properties, of which 33 wells were completed for production and eight were drilled but not yet completed or connected to a pipeline. Permits to drill four additional wells on the properties had been issued by regulatory agencies.

FAYETTEVILLE SHALE, 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. Three hundred ten wells have been permitted on the lands as of March 31, 2011, of which the operating partnership has an interest in 196. In total, 272 wells had been spud, 247 had been completed as producers and 25 were in various stages of drilling or completion operations or waiting on a pipeline. Wells that 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.

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Set forth below is a summary of Fayetteville Shale activity through March 31, 2011 for wells in which we have a royalty or Net Profits Interest. This includes wells subject to the Minerals NPI, which is currently in deficit status.

	2004						2004		Total
	through		Q1	Q2	Q3	Q4	Q1	to	
	2007	2008	2009	2010	2010	2010	2010	2011	Date
New Well									
Permits(1)	47	66	69	23	21	31	33	20	310
Wells Spud	41	62	70	23	15	27	20	14	272
Wells Completed(2)	27	53	49	13	33	18	26	28	247
Royalty Wells in									
Pay Status (3)	6	30	55	10	14	20	25	20	180

(1) Excludes permits that expire undrilled.

(2) Completing date defined as the day the well commences production.

(3) Wells in pay status means wells for which revenue was initially received during the indicated period.

Net cash receipts for the Royalty Properties attributable to interests in these lands totaled \$892,000 in the first quarter from 180 wells. Net cash receipts for the Minerals NPI Properties attributable to interests in these lands totaled approximately \$498,000 in the first quarter from 98 wells.

GRANITE WASH, TEXAS PANHANDLE – We own varying undivided perpetual mineral interests totaling 16,336/2,559 gross/net acres in Hemphill, Roberts and Wheeler Counties, Texas. Operators active in this area include Apache Corporation, Chesapeake Operating, Forest Oil, Linn Energy, Newfield Exploration, and QEP Resources. In 2010, we leased 680 net acres to two parties in two transactions for 25% royalty and total bonus consideration of \$2,892,560. As of March 31, 2011, two wells were drilling and one additional well was permitted to be drilled on the leased lands.

HORIZONTAL BAKKEN, WILLISTON BASIN – We own varying undivided perpetual mineral interests totaling 70,390/8,905 gross/net acres located in Burke, Divide, Dunn, McKenzie, Mountrail and Williams Counties, North Dakota. Operators active in this area include Continental Resources, EOG Resources, Hess Corporation, Marathon Oil Company, and Whiting Oil & Gas. There have been a total of 144 wells permitted on these lands as of March 31, 2011 with 101 completed as producers. In virtually all cases we have elected not to lease our lands and not to pay our share of well costs, thus becoming a non-consenting mineral owner. According to North Dakota law, non-consenting owners receive the average royalty rate from the date of first production and back-in for their full working interest after the operator has recovered 150% of drilling and completion costs. Once 150% payout occurs, the working interest will be owned by the operating partnership and subject to the Minerals NPI. Non-consenting owners are not entitled to well data other than public information available from the North Dakota Industrial Commission. As of March 31, 2011, eight of these wells had achieved 150% payout.

Set forth below is a summary of Horizontal Bakken activity through March 31, 2011 for wells in which we have a royalty or Net Profits Interest. This includes wells subject to the Minerals NPI, which is currently in a deficit status.

	2004						2004		Total
	through		Q1	Q2	Q3	Q4	Q1	to	
	2007	2008	2009	2010	2010	2010	2010	2011	Date
New Well Permits	17	44	22	6	17	10	21	7	144
Wells Spud	14	26	29	7	15	12	9	18	130
Wells Completed	9	22	31	9	6	12	10	2	101

Wells in Pay

Status(1)	0	3	1	1	0	3	0	0	8
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Wells in pay status means wells for which revenue was initially received during the indicated (1)period.

Liquidity and Capital Resources

Capital Resources

Our primary sources of capital are our cash flow from the NPIs and the Royalty Properties. Our only cash requirements are the distributions to our unitholders, the payment of oil and natural gas production and property taxes not otherwise deducted from gross production revenues and general and administrative expenses incurred on our behalf and allocated in accordance with our partnership agreement. Since the distributions to our unitholders are, by definition, determined after the payment of all expenses actually paid by us, the only cash requirements that may create liquidity concerns for us are the payments of expenses. Since most of these expenses vary directly with oil and natural gas sales prices and volumes, we anticipate that sufficient funds will be available at all times for payment of these expenses. See Note 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 plans to continue its efforts to increase production in Oklahoma with techniques that may include fracture treating, deepening, recompleting, and drilling. Costs vary widely and are not predictable as each effort requires specific engineering. Such activities by the operating partnership could influence the amount we receive from the NPIs as reflected in the accrual-basis production costs \$/mcf in the table under "Results of Operations."

The operating partnership owns and operates the wells, pipelines and natural gas compression and dehydration facilities located in Kansas and Oklahoma. The operating partnership 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 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 \$13,930,000 at March 31, 2011 and \$11,253,000 at December 31, 2010.

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 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 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 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 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 March 31, 2011 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

See Note 2 – Contingencies in Notes to the Condensed Consolidated Financial Statements.

ITEM 6. EXHIBITS

See the attached Index to Exhibits.

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SIGNATURES

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

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
Chief Executive Officer

Date: May 5, 2011

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

Date: May 5, 2011

INDEX TO EXHIBITS

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

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- 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)

* Filed herewith

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