DORCHESTER MINERALS LP
Form 10-Q
May 06, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
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 March 31, 2010 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 x No o

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 o No o

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

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

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

As of May 6, 2010, 30,675,431 common units of partnership interest were outstanding.

TABLE OF CONTENTS

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

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

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

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

PART I

ITEM 1. FINANCIAL INFORMATION

See attached financial statements on the following pages.

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

CONDENSED CONSOLIDATED BALANCE SHEETS
(In Thousands)

ASSETS	March 31, 2010 (unaudited)	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 14,718	$ 10,124
Trade and other receivables	6,580	5,419
Net profits interests receivable - related party	2,100	3,703
Prepaid expenses	37	-
Total current assets	23,435	19,246
Other non-current assets	19	19
Total	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	344,190	327,069
Accumulated full cost depletion	(198,045)	(193,822)
Total	146,145	133,247
Leasehold improvements	512	512
Accumulated amortization	(268)	(256)
Total	244	256
Net property and leasehold improvements	146,389	133,503
Total assets	$ 169,843	$ 152,768
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 937	$ 529
Current portion of deferred rent incentive	39	39
Total current liabilities	976	568
Deferred rent incentive less current portion	159	169

Total liabilities		1,135		737
Commitments and contingencies (Note 2)				
Partnership capital:				
General partner		5,193		5,240
Unitholders		163,515		146,791
Total partnership capital		168,708		152,031
Total liabilities and partnership capital	$	169,843	$	152,768

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,	
	2010	2009
Operating revenues:		
Royalties	$ 11,964	$ 7,025
Net profits interests	3,185	1,782
Lease bonus	372	9
Other	18	8
Total operating revenues	15,539	8,824
Costs and expenses:		
Operating, including production taxes	1,210	739
Depletion and amortization	4,235	3,300
General and administrative expenses	1,170	1,035
Total costs and expenses	6,615	5,074
Operating income	8,924	3,750
Other income, net	2	27
Net earnings	$ 8,926	$ 3,777
Allocation of net earnings:		
General partner	$ 292	$ 123
Unitholders	$ 8,634	$ 3,654
Net earnings per common unit (basic and diluted)	$ 0.29	$ 0.13
Weighted average common units outstanding	29,849	28,240

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

5

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

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

	Three Months Ended March 31,	
	2010	2009
Net cash provided by operating activities	$ 14,155	$ 11,735
Cash flows provided by (used in) investing activities:		
Adjustment related to acquisition of natural gas properties	407	-
Capital expenditures	(34)	(79)
Total cash flows provided by (used in) investing activities	373	(79)
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(9,934)	(15,828)
Increase (decrease) in cash and cash equivalents	4,594	(4,172)
Cash and cash equivalents at beginning of period	10,124	16,211
Cash and cash equivalents at end of period	$ 14,718	$ 12,039
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., newly acquired Maecenas Minerals LLP, and newly formed Dorchester-Maecenas GP LLC. Dorchester Minerals Acquisition LP and Dorchester Minerals Acquisition GP, Inc. were merged into Dorchester Minerals Oklahoma, LP and Dorchester Minerals Oklahoma GP, Inc., respectively, effective December 31, 2009. 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, 2009.

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. No court schedule has been set. 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, for 835,000 common units of Dorchester Minerals, L.P. valued at $17,685,000 and issued pursuant to a shelf registration statement. The Condensed Consolidated Balance Sheet as of March 31, 2010 includes $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 2006 have been:

	Per Unit Amount				
	2010	2009	2008	2007	2006
First quarter	$0.449222	$0.401205	$0.572300	$0.461146	$0.729852
Second quarter		$0.271354	$0.769206	$0.473745	$0.778120
Third quarter		$0.286968	$0.948472	$0.560502	$0.516082
Fourth quarter		$0.321540	$0.542081	$0.514625	$0.478596

Distributions for the first quarter of 2010 will be 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 2010 distribution will be paid May 10, 2010. 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, 2010.

5 New Accounting Pronouncements: None.

6 Subsequent Events: We evaluated subsequent events through the date the financial statements were issued and are not aware of any subsequent events, which are not already recognized or disclosed, that would require recognition or disclosure in the financial statements.

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 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 and one immaterial deficit NPI subsequently created. 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. 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, 2010, 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 12/31/09	Three Months Ended 3/31/10	Cumulative Total at 3/31/10
Cash received for revenue	$ 17,624	$ 1,462	$ 19,086
Cash paid for operating costs	3,091	369	3,460
Cash paid for development costs	16,072	611	16,683
Budgeted capital expenditures	1,795	99	1,894
Net	$ (3,334)	$ 383	$ (2,951)

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, 2010 as compared to Three Months Ended March 31, 2009

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,	
Accrual basis sales volumes:	2010	2009
Royalty properties gas sales (mmcf)	1,247	1,037
Royalty properties oil sales (mbbls)	75	74
NPI gas sales (mmcf)	832	887
NPI oil sales (mbbls)	2	3
Accrual basis weighted average sales price:		

Royalty properties gas sales ($/mcf)	$ 5.14	$ 4.05
Royalty properties oil sales ($/bbl)	$ 74.44	$ 38.45
NPI gas sales ($/mcf)	$ 5.23	$ 3.32
NPI oil sales ($/bbl)	$ 70.33	$ 28.63
Accrual basis production costs deducted under the NPIs ($/mcfe) (1)	$ 1.68	$ 1.45

(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 2010 were about the same as first quarter 2009. Natural gas sales volumes attributable to our Royalty Properties during first quarter 2010 increased 20.3% from 1,037 mmcf in 2009 to 1,247 mmcf in 2010. The increase in natural gas sales volumes was primarily attributable to the acquisition of properties in the Barnett Shale during the second quarter of 2009 and continued development activities on the Royalty Properties.

Oil sales volumes attributable to our NPIs during first quarter 2010 were about the same as first quarter 2009. Natural gas sales volumes attributable to our NPIs during first quarter 2010 decreased 6.2% from 887 mmcf during first quarter 2009 to 832 mmcf during first quarter 2010. 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 93.6% from $38.45/bbl during first quarter 2009 to $74.44/bbl during first quarter 2010. First quarter weighted average natural gas sales prices from Royalty Properties increased 26.9% from $4.05/mcf during 2009 to $5.14/mcf during 2010. Both oil and natural gas price changes resulted from changing market conditions.

First quarter weighted average oil sales prices from the NPIs increased 145.7% from $28.63/bbl in 2009 to $70.33/bbl in 2010. Weighted average natural gas sales prices attributable to the NPIs increased 57.5% from $3.32/mcf during first quarter 2009 to $5.23/mcf during first quarter 2010. Changing market conditions resulted in increased oil and natural gas prices.

Our first quarter total operating revenues increased 76.1% from $8,824,000 during 2009 to $15,539,000 during 2010 as a result of increased oil and natural gas sales prices.

Costs and expenses increased 30.4% from $5,074,000 during first quarter 2009 to $6,615,000 during first quarter 2010 primarily as a result of increased depletion related to the Barnett Shale acquisition on June 30, 2009 along with increased production tax on higher operating revenues.

Depletion and amortization increased 28.3% from $3,300,000 during first quarter 2009 to $4,235,000 during first quarter 2010 primarily due to a higher depletable base after the June 30, 2009 acquisition of properties in the Barnett Shale.

First quarter net earnings allocable to common units increased 136.3% from $3,654,000 during 2009 to $8,634,000 during 2010 primarily due to increased oil and natural gas sales prices.

Net cash provided by operating activities increased 20.6% from $11,735,000 during first quarter 2009 to $14,155,000 during first quarter 2010 primarily due to increased 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 2010 totaled approximately $10,500,000. These receipts generally reflect oil sales during December 2009 through February 2010 and natural gas sales during November 2009 through January 2010. The weighted average indicated prices for oil and natural gas sales during first quarter 2010 attributable to the Royalty Properties were $72.23/bbl and $4.64/mcf, respectively.

Cash receipts attributable to our NPIs during first quarter 2010 totaled approximately $4,800,000. These receipts reflect oil and natural gas sales from the properties underlying the NPIs generally during November 2009 through January 2010. The weighted average indicated prices received during first quarter 2010 for oil and natural gas sales were $66.97/bbl and $7.03/mcf, respectively. The natural gas weighted average indicated price for the quarter was increased by $2.09/mcf due to the receipt of a natural gas liquids payment of $1,700,000 for 2009 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 $214,000 from various sources during first quarter 2010 including lease bonuses attributable to 21 consummated leases located in 11 counties and parishes in four states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to $1,200/acre.

We received division orders for, or otherwise identified, 97 new wells completed on our Royalty Properties and NPIs located in 32 counties and parishes in six states during the first quarter of 2010. The operating partnership elected to participate in nine wells to be drilled on our NPIs located in four counties in two 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 tables below.

This table does not include wells drilled in the Fayetteville Shale trend as they are detailed in a subsequent discussion and table.

State	County /Parish	Operator	Well Name	DMLP NRI(2)	DMOLP WI(1)	DMOLP NRI(2)	Test Rates per day Gas, mcf	Test Rates per day Oil, bbls
ND	Dunn	Marathon Oil Co.	Dirkach 34-9H	1.497%	--	--	147	384
TX	Dawson	Fasken Oil and Ranch	Jacksonville College "9" No. 1	6.250%	--	--	73	147
TX	Hemphill	Noble Energy	Flowers 15-226	3.140%	--	--	924	--
TX	Panola	Anadarko E & P	L.T. Poss Unit 15H	0.268%	--	--	3,682	--
TX	Starr	Ram Operating	Garza Hitchcock 19	2.653%	--	--	2,187	--
TX	Tarrant	Chesapeake Operating	Duck Lake 10H	17.063%	--	--	3,456	--
TX	Tarrant	Chesapeake Operating	Duck Lake 11H	17.063%	--	--	3,507	--

(1) WI means the working interest owned by the operating partnership and subject to an NPI.

(2) NRI means the net revenue interest attributable to our royalty interest or to the operating partnership's royalty and working interest, which is subject to an NPI.

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. Two hundred fifteen wells have been permitted on the lands as of March 31, 2010. 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. Available test results for new wells producing in the first quarter, along with ownership interests owned by us and interests owned by the operating partnership subject to the Minerals NPI, are summarized in the following table.

County	Operator	Well Name	DMLP NRI(2)	DMOLP WI(1)	DMOLP NRI(2)	Gas Test Rates mcf per day
Conway	Chesapeake	Collinsworth 7-16 #3-10H	2.305%	0.000%	0.000%	3,898
Conway	Chesapeake	E. Rowell 8-16 #2-35H34	0.781%	0.000%	0.000%	2,720
Van Buren	Chesapeake	Bixler 11-13 #1-9H	1.563%	1.254%	0.941%	1,711
Van Buren	SEECO	Day 9-12 #2-32H31	1.563%	1.250%	0.938%	995
Van Buren	SEECO	Holland-Smith 9-13 #1-36H	1.563%	1.250%	0.938%	1,800
Van Buren	SEECO	McClain 10-15 #1-5H	0.684%	0.000%	0.000%	2,248
Van Buren	Chesapeake	Roy Clark 11-13 #2-4H9	1.305%	0.000%	0.000%	1,252
Van Buren	Chesapeake	Sherry Bixler 11-13 #1-9H5	0.157%	0.252%	0.189%	1,112
Van Buren	Chesapeake	Sherry Bixler 11-13 #2-9H4	0.222%	0.178%	0.133%	817
Van Buren	SEECO	Stevens 11-15 #2-22H27	1.826%	2.300%	1.725%	2,761
White	SEECO	Riley 9-6 #1-22H	3.125%	5.000%	3.750%	--
White	SEECO	Riley 9-6 #2-22H	0.036%	0.000%	0.000%	--
White	SEECO	Shaver 9-6 #1-27H	0.781%	0.000%	0.000%	--

(1) WI means the working interest owned by the operating partnership and subject to the Minerals NPI.

(2)

NRI means the net revenue interest attributable to our royalty interest or to the operating partnership's royalty and working interest, which is subject to an NPI.

Set forth below is a summary of all permitting, drilling and completion activity through March 31, 2010 for wells in which we have a royalty interest or NPI. This includes wells subject to the Minerals NPI, which is currently in a deficit status.

	2004 through 2006	2007	2008	Q1 2009	Q2 2009	Q3 2009	Q4 2009	Q1 2010	Total to Date
New Well Permits(1)	12	35	71	19	20	22	14	22	215
Wells Spud	10	31	62	22	16	8	22	19	190
Wells Completed	6	23	56	13	14	14	16	11	153
Royalty Wells in Pay Status(2)	1	14	32	14	10	14	20	5	110

(1) Excludes permits that expire undrilled.
(2) 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 $572,000 in the first quarter from 97 wells. Net cash receipts for the Minerals NPI Properties attributable to interests in these lands totaled approximately $829,000 in the first quarter from 66 wells.

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, 2010, 35 wells were drilled from 11 padsites located on or adjacent to the properties, of which 29 wells were completed for production and six were drilled but not yet completed or connected to a pipeline. Permits to drill six additional wells on the properties had been issued by regulatory agencies.

HORIZONTAL BAKKEN, WILLISTON BASIN – We own varying undivided perpetual mineral interests totaling 70,390/7,602 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 and Marathon Oil Company. Eighty-seven wells have been permitted on these lands as of March 31, 2010. In 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 will be subject to the Minerals NPI or a newly created Maecenas NPI. Non-consenting owners are not entitled to well data other than public information available from the North Dakota Industrial Commission.

Set forth below are totals and a summary of permitting, drilling and completion activity through March 31, 2010 for wells in which we have a royalty or NPI.

2004 through 2006	2007	2008	Q1 2009	Q2 2009	Q3 2009	Q4 2009	Q1 2010	Total to Date

New Well Permits	3	15	46	0	6	0	15	2	87
Wells Spud	2	12	27	12	4	7	7	7	78
Wells Completed	2	7	23	9	9	9	4	2	65
Wells in Pay Status(1)	0	0	3	0	0	0	0	0	3

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

APPALACHIAN BASIN — We own varying undivided perpetual mineral interests in approximately 31,000/22,000 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 in 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.

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 $/mcfe in the table under “Results of Operations.”

The operating partnership owns and operates the wells, pipelines and natural gas compression and dehydration facilities located in Kansas and Oklahoma. The operating partnership 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 $14,718,000 at March 31, 2010 and $10,124,000 at December 31, 2009.

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. Effective December 31, 2009, 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, 2010 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II

ITEM 1. LEGAL PROCEEDINGS

See Note 2 – Contingencies in Notes to the Condensed Consolidated 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. (REMOVED AND RESERVED)

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

	By: /s/ William Casey McManemin William Casey McManemin
Date: May 6, 2010	Chief Executive Officer
	By: /s/ H.C. Allen, Jr. H.C. Allen, Jr.
Date: May 6, 2010	Chief Financial Officer

16

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)
10.1	Contribution and Exchange Agreement dated March 31, 2010 by and among Dorchester Minerals, L.P., Dodge Jones Foundation, The Legett Foundation, Kickapoo Springs Foundation, The Karakin Foundation, Still Water Foundation, Xettam Minerals, L.P., 2MW Limited Partnership, Julia Jones Matthews, Trustee of the Julia Jones Matthews Living Trust, and John A. Matthews, Jr. (incorporated by reference to Exhibit 10.1 to Dorchester Minerals' Report on Form 8-K (filed April 6, 2010).
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)

* *Filed herewith