DORCHESTER MINERALS LP
Form 10-Q
August 06, 2009

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 June 30, 2009 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 August 6, 2009, 29,840,431 common units of partnership interest 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 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.

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

CONDENSED CONSOLIDATED BALANCE SHEETS
(In Thousands)

ASSETS	June 30, 2009 (unaudited)	December 31, 2008
Current assets:		
Cash and cash equivalents	$ 9,217	$ 16,211
Trade and other receivables	4,573	5,053
Net profits interests receivable - related party	1,183	4,428
Prepaid expenses	25	-
Total current assets	14,998	25,692
Other non-current assets	19	19
Total	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	327,063	291,818
Accumulated full cost depletion	(185,021)	(178,272)
Total	142,042	113,546
Leasehold improvements	512	512
Accumulated amortization	(231)	(207)
Total	281	305
Net property and leasehold improvements	142,323	113,851
Total assets	$ 157,340	$ 139,562
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 1,010	$ 733
Current portion of deferred rent incentive	39	39
Total current liabilities	1,049	772
Deferred rent incentive less current portion	188	208
Total liabilities	1,237	980

Commitments and contingencies				
Partnership capital:				
General partner		5,422		5,971
Unitholders		150,681		132,611
Total partnership capital		156,103		138,582
Total liabilities and partnership capital	$	157,340	$	139,562

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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Operating revenues:				
Royalties	$ 8,006	$ 18,604	$ 15,031	$ 33,375
Net profits interests	1,593	10,204	3,375	16,569
Lease bonus	80	140	89	257
Other	5	40	13	59
Total operating revenues	9,684	28,988	18,508	50,260
Costs and expenses:				
Operating, including production taxes	844	1,345	1,583	2,536
Depletion and amortization	3,473	3,648	6,773	7,438
General and administrative expenses	817	860	1,852	1,871
Total costs and expenses	5,134	5,853	10,208	11,845
Operating income	4,550	23,135	8,300	38,415
Other income, net	170	31	197	161
Net earnings	$ 4,720	$ 23,166	$ 8,497	$ 38,576
Allocation of net earnings:				
General partner	$ 161	$ 662	$ 284	$ 1,125
Unitholders	$ 4,559	$ 22,504	$ 8,213	$ 37,451
Net earnings per common unit (basic and diluted)	$ 0.16	$ 0.80	$ 0.29	$ 1.33
Weighted average common units outstanding	28,258	28,240	28,249	28,240

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)

	Six Months Ended June 30, 2009		Six Months Ended June 30, 2008	
Net cash provided by operating activities	$	19,511	$	39,886
Cash flows provided by (used in) investing activities:				
Adjustment related to acquisition of natural gas properties		967		-
Capital expenditures		-		(50)
Total cash flows provided by (used in) investing activities		967		(50)
Cash flows used in financing activities:				
Distributions paid to general partner and unitholders		(27,472)		(31,662)
(Decrease) increase in cash and cash equivalents		(6,994)		8,174
Cash and cash equivalents at beginning of period		16,211		15,001
Cash and cash equivalents at end of period	$	9,217	$	23,175
Non-cash investing and financing activities:				
Value of units issued for natural gas properties acquired	$	36,496		

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., Dorchester Minerals Oklahoma LP, Dorchester Minerals Oklahoma GP, Inc., Dorchester Minerals Acquisition LP, and Dorchester Minerals Acquisition GP, Inc. 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, 2008.

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 Net Profits Interests 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. At present, the litigation awaits result of the appeal to the Oklahoma Supreme Court. An adverse appellate 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 consolidated financial position, cash flows, or operating results.

3. Acquisition for Units: On June 30, 2009, we acquired producing and non-producing Barnett Shale mineral and royalty interests located in Tarrant County, Texas for 1,600,000 common units of Dorchester Minerals, L.P. issued pursuant to a shelf registration statement. Net assets acquired at the date of acquisition totaled $36,496,000. The

Condensed Consolidated Balance Sheets presented include $35,245,000 in property additions. After the issuance, 3,400,000 units remain available under the shelf registration statement.

4. Distributions to Holders of Common Units: Unitholder cash distributions per common unit since 2005 have been:

	Per Unit Amount				
	2009	2008	2007	2006	2005
First quarter	$0.401205	$0.572300	$0.461146	$0.729852	$0.481242
Second quarter	$0.271354	$0.769206	$0.473745	$0.778120	$0.514542
Third quarter		$0.948472	$0.560502	$0.516082	$0.577287
Fourth quarter		$0.542081	$0.514625	$0.478596	$0.805543

Distributions beginning with the second quarter of 2009 were paid on 29,840,431 units; previous distributions above were paid on 28,240,431 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, 2009.

5. New Accounting Pronouncements: In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. SFAS 157 also emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Under SFAS 157, fair value measurements are disclosed by level within that hierarchy. In February 2008, the FASB issued FASB Staff Position 157-2, Effective Date of FASB Statement No. 157 which permits a one year deferral for the implementation of SFAS 157 with regard to nonfinancial assets and liabilities that are not recognized or disclosed at fair value in the financial statements on a recurring basis. We adopted SFAS 157 for the fiscal year beginning January 1, 2008 with no material impact on our consolidated financial statements. We adopted the delayed portion for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis beginning January 1, 2009 with no material impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS 141 (revised 2007), Business Combinations (SFAS 141(R)). SFAS 141(R), among other things, establishes principles and requirements for how the acquirer in a business combination (a) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquired business, (b) changes the accounting for contingent consideration, in process research and development, and restructuring costs, (c) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (d) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. We adopted SFAS 141(R) as of January 1, 2009. The adoption had no material impact on our consolidated financial statements.

In April 2009, the FASB issued FSP No. 107-1 and Accounting Principles Board (APB) 28-1, Interim Disclosures about Fair Value of Financial Instruments ("FSP 107-1"). FSP 107-1 requires disclosures about fair value of financial instruments for interim reporting periods and amends APB Opinion No. 28 Interim Financial Reporting to require those disclosures in summarized financial information at interim reporting periods. The FSP is effective for the period ended June 30, 2009 and did not have a material impact on the consolidated financial statements.

On June 29, 2009, the FASB issued SFAS 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles. SFAS No. 168 defines the new hierarchy for U.S. GAAP and explains how the FASB will use its Accounting Standards Codification as the sole source for all authoritative guidance. SFAS 168 replaces SFAS 162, The Hierarchy of Generally Accepted Accounting Principles, which was issued in May 2008. The Codification will be effective for all reporting periods that end after September 15, 2009. We expect no material impact on our consolidated financial statements from SFAS 168.

In May 2009, the FASB issued SFAS 165, Subsequent Events, to incorporate the accounting and disclosure requirements for subsequent events into U.S. generally accepted accounting principles. SFAS 165 introduces new terminology, defines a date through which management must evaluate subsequent events, and lists the circumstances under which an entity must recognize and disclose events or transactions occurring after the balance-sheet date. We adopted SFAS 165 as of June 30, 2009, which was the required effective date.

6. Subsequent Events: We evaluated subsequent events through August 6, 2009 which represents the date the financial statements were issued. We are not aware of any subsequent events which 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 Net Profits Interests, 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 Net Profits Interests 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 Net Profits Interest, referred to as the Minerals NPI, has continuously had costs that exceed revenues. As of June 30, 2009, 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 Net Profits Interest payments attributable to these properties. Our consolidated 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 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 12/31/08	Six Months Ended 6/30/09	Cumulative Total at 6/30/09
Cash received for revenue	$ 14,216	$ 1,538	$ 15,754
Cash paid for operating costs	2,226	384	2,610
Cash paid for development costs	11,724	2,076	13,800
Budgeted capital expenditures	905	948	1,853
Net	$ (639)	$ (1,870)	$ (2,509)

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. 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 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 Net Profits Interest 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 and Six Months Ended June 30, 2009 as compared to Three and Six Months Ended June 30, 2008

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:	2009	2008	2009	2009	2008
Royalty properties gas sales (mmcf)	1,019	872	1,037	2,056	1,864
Royalty properties oil sales (mbbls)	80	80	74	154	152
Net profits interests gas sales (mmcf)	903	974	887	1,790	1,961
Net profits interests oil sales (mbbls)	3	3	3	6	7
Accrual basis weighted average sales price:					
Royalty properties gas sales ($/mcf)	$ 3.47	$ 10.73	$ 4.05	$ 3.76	$ 9.26
Royalty properties oil sales ($/bbl)	$ 55.90	$ 116.43	$ 38.45	$ 47.54	$ 106.14
Net profits interests gas sales ($/mcf)	$ 2.95	$ 11.90	$ 3.32	$ 3.13	$ 9.96
Net profits interests oil sales ($/bbl)	$ 55.70	$ 116.81	$ 28.63	$ 42.07	$ 98.18
Accrual basis production costs deducted under the net profits interests ($/mcfe) (1)	$ 1.41	$ 1.94	$ 1.45	$ 1.43	$ 1.96

(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 were unchanged at 80 mbbls in 2009 and in 2008. Oil sales volumes attributable to our Royalty Properties during the first six months were also virtually unchanged at 154 mbbls in 2009 compared to 152 mbbls in 2008. Natural gas sales volumes attributable to our Royalty Properties during the second quarter increased 16.9% from 872 mmcf in 2008 to 1,019 mmcf in 2009. Natural gas sales volumes attributable to our Royalty Properties during the first six months increased 10.3% from 1,864 in 2008 to 2,056 mmcf in 2009. The increase in natural gas sales volumes was primarily attributable to results from new drilling activity in the second half of 2008.

Oil sales volumes attributable to our Net Profits Interests during the second quarter and first six months of 2009 were virtually unchanged when compared to the same periods of 2008. Natural gas sales volumes attributable to our Net Profits Interests during the second quarter and first six months of 2009 decreased from the same periods of 2008. Second quarter sales volumes of 903 mmcf during 2009 were 7.3% less than 974 mmcf during 2008. First six month sales volumes of 1,790 mmcf during 2009 were 8.7% less than 1,961 mmcf during 2008. Both natural gas sales volume decreases were 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 decreased 52.0% from $116.43/bbl during the second quarter of 2008 to $55.90/bbl during the second quarter of 2009 and decreased 55.2% from $106.14/bbl during the first six months of 2008 to $47.54/bbl during the same period of 2009. Second quarter weighted average natural gas sales prices from Royalty Properties decreased 67.7% from $10.73/mcf during 2008 to $3.47/mcf during 2009. The six months ended June 30 weighted average Royalty Properties natural gas sales prices decreased 59.4% from $9.26/mcf during 2008 to $3.76/mcf during 2009. 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 decreased 52.3% from $116.81/bbl in 2008 to $55.70/bbl in 2009. The first six months Net Profits Interests’ oil sales prices decreased 57.2% from $98.18/bbl in 2008 to $42.07/bbl in 2009. Changing market conditions resulted in decreased oil prices. Weighted average natural gas sales prices attributable to the Net Profits Interests decreased during the second quarter of 2009 and first six months of 2009 compared to the same periods of 2008. Second quarter natural gas sales prices of $2.95/mcf in 2009 were 75.2% less than $11.90/mcf in 2008. The six months ended June 30, 2009 natural gas prices decreased 68.6% to $3.13/mcf from $9.96/mcf in the same period of 2008. Natural gas sales price decreases during the three- and six- month periods resulted from changing market conditions along with a natural gas liquids payment received in 2008 that related to prior year 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. 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.

Our second quarter net operating revenues decreased 66.6% from $28,988,000 during 2008 to $9,684,000 during 2009. Net operating revenues for the first six months of 2009 decreased 63.2% from $50,260,000 during 2008 to $18,508,000 during 2009. Both the quarterly and six-month decrease resulted from decreased gas and oil sales prices including a 2007 natural gas liquid payment received during the second quarter 2008.

Costs and expenses decreased 12.3% from $5,853,000 during the second quarter of 2008 to $5,134,000 during the second quarter of 2009, while six months ended June 30 costs and expenses decreased 13.8% from $11,845,000 during 2008 to $10,208,000 during 2009. Such decreases primarily resulted from decreased production tax on lower operating revenues and reduced depletion and amortization.

Depletion and amortization decreased 4.8% during the second quarter ended June 30, 2009 and 8.9% during the six months ended June 30, 2009 when compared to the same periods of 2008. The decreases from $3,648,000 and $7,438,000 during the second quarter and six months ended June 30, 2008, respectively, to $3,473,000 and $6,773,000 during the same periods of 2009 respectively, resulted from a lower depletable base due to effects of previous depletion and upward revisions in oil and natural gas reserve estimates at 2008 year end.

Second quarter net earnings allocable to common units decreased 79.7% from $22,504,000 during 2008 to $4,559,000 during 2009. First six months common unit net earnings decreased 78.1% from $37,451,000 during 2008 to $8,213,000 during 2009. Both decreases are primarily the result of decreased oil and natural gas sales prices.

Net cash provided by operating activities decreased 65.7% from $22,683,000 during the second quarter of 2008 to $7,776,000 during the second quarter of 2009 and decreased 51.1% from $39,886,000 for the first six months during 2008 to $19,511,000 during the same period of 2009. Decreases in both periods are primarily due to decreased oil and natural gas sales prices. Abnormal natural gas liquid payments were also received in first quarter 2009 and second quarter 2008. See discussion above on net operating revenues for more details.

In an effort to provide the reader with information concerning prices of oil and natural gas sales that correspond to our quarterly distributions, management calculates the weighted average price by dividing gross revenues received by the net volumes of the corresponding product without regard to the timing of the production to which such sales may be attributable. This “indicated price” does not necessarily reflect the contract terms for such sales and may be affected by transportation costs, location differentials, and quality and gravity adjustments. While the relationship between our cash receipts and the timing of the production of oil and natural gas may be described generally, actual cash receipts may be materially impacted by purchasers’ release of suspended funds and by purchasers’ prior period adjustments.

Cash receipts attributable to our Royalty Properties during the 2009 second quarter totaled $7,009,000. These receipts generally reflect oil sales during March through May 2009 and natural gas sales during February through April 2009. The weighted average indicated prices for oil and natural gas sales during the 2009 second quarter attributable to the Royalty Properties were $46.58/bbl and $3.75/mcf, respectively.

Cash receipts attributable to our Net Profits Interests during the 2009 second quarter totaled $1,532,000. These receipts reflect oil and natural gas sales from the properties underlying the Net Profits Interests generally during February through April 2009. The weighted average indicated prices received during the 2009 second quarter for oil and natural gas sales were $37.91/bbl and $2.94/mcf, respectively.

We received cash payments in the amount of $249,000 from various sources during the second quarter of 2009 including lease bonuses attributable to ten consummated leases and pooling elections located in five counties and parishes in three states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to $200/acre.

Our second quarter cash distribution included $1,067,000 of second quarter cash receipts from the acquired Barnett Shale properties. This cash payment contained non-recurring items and, therefore, may not be reflective of future cash generated by the acquired properties. See Note 3 to the consolidated financial statements and Barnett Shale discussion below.

We received division orders for, or otherwise identified, 106 new wells completed on our Royalty Properties and Net Profits Interests located in 46 counties and parishes in 11 states during the second quarter of 2009. The operating partnership elected to participate in 20 wells to be drilled on our Net Profits Interests located in seven 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.

	County			DMLP	DMOLP		Test Rates per day	
State	/Parish	Operator	Well Name	NRI(2)	WI(1)	NRI(2)	Gas, mcf	Oil, bbls
OK	Ellis	Crusader Energy	Raiders 5-27H	--	3.750%	9.063%	1,142	176
TX	Starr	El Paso E&P Co.	Guerra USA GU “D” #17	8.194%	--	--	6,800	--
TX	Starr	El Paso E&P Co.	Guerra USA GU “D” #18	8.194%	--	--	366	5
TX	Starr	Ram Operating Co.	Garza Hitchcock #18	2.653%	--	--	2,491	--
TX	Wheeler	Kaiser-Francis	Burrell A W 104	0.710%	--	--	8,964	--

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

(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 a 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. One hundred fifty-seven wells have been permitted on the lands as of June 30, 2009. 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 second 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.

			DMLP	DMOLP		Gas Test Rates
County	Operator	Well Name	NRI(2)	WI(1)	NRI(2)	mcf per day
Cleburne	SEECO	Mulliniks 9-12 #6-35H2	1.401%	1.992%	1.494%	4,323
Conway	Chesapeake	Collinsworth 7-16 #1-10H3	2.312%	4.553%	3.414%	--
Conway	SEECO	Charles Reeves 9-15 #3-10H3	2.849%	4.559%	3.419%	3,976
Conway	SEECO	Charles Reeves 9-15 #4-10H3	2.974%	4.758%	3.569%	1,895
Conway	SEECO	Charles Reeves 9-15 #5-10H3	2.974%	4.375%	3.569%	3,884
Conway	SEECO	Polk 9-15 #4-30H	5.930%	5.561%	4.220%	--
Faulkner	Chesapeake	Hooten 8-12 #1-17H	0.752%	0.000%	0.000%	--
Van Buren	Petrohawk	Green Bay 11-14 #1-20H	0.703%	0.000%	0.000%	--
Van Buren	Petrohawk	Thacker 9-12 #2-21H	2.343%	4.375%	3.281%	1,538
Van Buren	SEECO	Howard Family Trust 10-12 #2-9H16	2.594%	4.576%	3.432%	--
Van Buren	SEECO	Collums-Pennington 10-12 #1-20H	2.344%	4.375%	3.281%	2,081

Van Buren	SEECO	Collums-Pennington 10-12 #2-20H	2.344%	4.375%	3.281%	2,229
White	Chesapeake	Gillam 9-6 #1-23H	3.125%	5.000%	3.750%	820
White	Chesapeake	Webb 9-6 #1-35H	2.344%	4.380%	3.285%	2,389

(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 the Minerals NPI.

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Set forth below are totals and a summary of permitting, drilling and completion activity through June 30, 2009 for wells in which we have a royalty interest or Net Profits Interest. This includes wells subject to the Minerals NPI, which is currently in a deficit status.

	Total to date (2)	Year 2006	Year 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009
New Well Permits	157	11	35	16	21	12	21	19	19
Wells Spud	132	9	33	12	17	19	13	21	7
Wells Completed	111	5	23	10	17	12	17	12	14
Wells in Pay Status (1)	71	0	14	4	7	14	7	14	10

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

(2) Includes activity begun in year 2004.

Net cash receipts for the Royalty Properties attributable to interests in these lands totaled $306,000 in the second quarter from 57 wells. Net cash receipts for the Minerals NPI Properties attributable to interests in these lands totaled $337,000 in the second quarter from 37 wells.

BARNETT SHALE — On May 15, 2009, we executed a definitive agreement to acquire 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 May 15, 2009, 32 wells were drilled from 11 padsites located on or adjacent to the properties, of which 26 wells were completed for production and six 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.

The transaction was consummated on June 30, 2009 and was structured as a non-taxable contribution and exchange. At the closing, in addition to conveying their interests to us, the contributing parties delivered funds in an amount equal to their cash receipts less cash disbursements during period April 1, 2009 through June 30, 2009 and we conveyed an aggregate of 1,600,000 common limited partnership units to the contributing parties. The funds delivered at closing totaled $1,067,000; approximately $520,000 of these funds were attributable to the production during January, February and March 2009. The balance of the funds was attributable to prior production periods and primarily due to one-time release of production revenues previously suspended by the purchaser.

Estimated proved developed reserves of 5,584.6 mmcf were assigned to the acquired properties as of June 30, 2009 based on the report of independent petroleum engineering consultant firm Huddleston & Co., Inc. These reserves include proved developed nonproducing reserves assigned to six wells. No proved undeveloped reserves were assigned to four permitted but undrilled locations or otherwise to the properties.

As of July 31, 2009, one of these six wells had been completed and was producing to sales. In addition, one of the permitted locations had been drilled and was waiting on completion and one other was drilling.

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. We are monitoring industry activity and encouraging dialogue with industry participants to determine the proper course of action regarding our interests.

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. Seventy-two wells have been permitted on these lands as of June 30, 2009. 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 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.

Set forth below are totals and a summary of permitting, drilling and completion activity through June 30, 2009 for wells in which we have a royalty interest or Net Profits Interest.

	Total to Date(2)	Year 2006	Year 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009
New Well Permits	72	0	15	8	16	15	12	0	3
Wells Spud	58	0	12	2	10	10	9	11	2
Wells Completed	44	0	7	5	5	10	6	8	1
WI Wells in Pay Status(1)	3	0	0	0	2	1	0	0	0

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

(2) Includes Activity begun in year 2004.

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 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 of such techniques vary widely and are not predictable as each effort requires specific engineering. 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 influence the Net Profits Interests payments we receive from the operating partnership and are included in the accrual basis production costs $/mcfe in the table under “Results of Operations.”

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 $9,217,000 at June 30, 2009 and $16,211,000 at December 31, 2008.

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 natural 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 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 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 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 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 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, 2009 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 in Notes to the Condensed Consolidated Financial Statements.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2008, other than the following:

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

The Proposed Fiscal Year 2010 Federal Budget includes legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration activities. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available to our common unitholders and to oil and gas operators that we rely upon to develop our properties. Such legislation or changes could negatively impact both our unitholders and our Partnership financially.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas production from our properties.

On June 26, 2009, the U.S. House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "cap-and-trade legislation" or ACESA. One of the purposes of ACESA is to control and reduce emissions of "greenhouse gases," or "GHGs," in the United States. GHGs are certain gases, including carbon dioxide and methane, which may be contributing to warming of the Earth's atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require a gradual overall reduction in GHG emissions. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require the operating partnership and oil and gas operators that develop our properties to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas produced from our properties.

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

We held our Annual Unitholders meeting on Wednesday, May 13, 2009 in Dallas, Texas. 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. The only matter voted on at the meeting was the election of the three nominees to the Board of Managers. Out of the 28,240,431 units then issued and outstanding and entitled to vote at the meeting, 26,463,922 units were present in person or by proxy. The results were as follows:

Nominee	Votes for Election	Votes Withheld from Election	Broker Non-Votes
Buford P. Berry	26,122,933	340,989	1,776,509
C. W. “Bill” Russell	26,182,863	281,059	1,776,509
Ronald P. Trout	26,186,512	277,410	1,776,509

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
Chief Executive Officer

Date: August 6, 2009

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

Date: August 6, 2009

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)

Number	Description
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)
10.1	Contribution and Exchange Agreement by and among Dorchester Minerals, L.P., Tiggator, Inc., TRB Minerals, LP and West Fork Partners, L.P. dated May 15, 2009 (incorporated by reference to Exhibit 10.1 to Dorchester Minerals' Current Report on Form 8-K filed on July 6, 2009).
10.2*	Amendment No. 1 dated June 26, 2009 to the Contribution and Exchange Agreement by and among Dorchester Minerals, L.P., Tiggator, Inc., TRB Minerals, LP and West Fork Partners, L.P. dated May 15, 2009
10.3	Lock-up Agreement by and between Dorchester Minerals, L.P. and Tiggator, Inc. dated June 30, 2009 (incorporated by reference to Exhibit 10.2 to Dorchester Minerals' Current Report on Form 8-K filed on July 6, 2009).
10.4	Lock-up Agreement by and between Dorchester Minerals, L.P. and TRB Minerals, LP dated June 30, 2009 (incorporated by reference to Exhibit 10.3 to Dorchester Minerals' Current Report on Form 8-K filed on July 6, 2009).
10.5	Lock-up Agreement by and between Dorchester Minerals, L.P. and West Fork Partners, L.P. dated June 30, 2009 (incorporated by reference to Exhibit 10.4 to Dorchester Minerals' Current Report on Form 8-K filed on July 6, 2009).
23.1*	Consent of Huddleston & Co., Inc.
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

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