DORCHESTER MINERALS LP
Form 10-Q
August 07, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC. 20549

FORM 10-Q

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

For the transition period from __________ to __________

For the Quarterly Period Ended June 30, 2008 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 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	Smaller reporting company o

(Do not check if a smaller reporting company)

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

As of August 7, 2008, 28,240,431 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	June 30, 2008 (unaudited)	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 23,175	$ 15,001
Trade receivables	11,066	7,053
Net profits interests receivable - related party	6,116	3,576
Prepaid expenses	25	-
Total current assets	40,382	25,630
Other non-current assets	19	19
Total	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	291,818	291,830
Less accumulated full cost depletion	170,996	163,582
Total	120,822	128,248
Leasehold improvements	512	512
Less accumulated amortization	182	158
Total	330	354
Net property and leasehold improvements	121,152	128,602
Total assets	$ 161,553	$ 154,251
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 926	$ 517
Current portion of deferred rent incentive	39	39
Total current liabilities	965	556
Deferred rent incentive less current portion	227	248
Total liabilities	1,192	804
Commitments and contingencies		
Partnership capital:		
General partner	6,575	6,417
Unitholders	153,786	147,030
Total partnership capital	160,361	153,447

Total liabilities and partnership capital	$	161,553	$	154,251

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,	
	2008	2007	2008	2007
Operating revenues:				
Royalties	$ 18,604	$ 11,113	$ 33,375	$ 20,782
Net profits interests	10,204	6,257	16,569	11,201
Lease bonus	140	224	257	317
Other	40	19	59	27
Total operating revenues	28,988	17,613	50,260	32,327
Costs and expenses:				
Operating, including production taxes	1,345	1,023	2,536	1,991
Depletion and amortization	3,648	3,873	7,438	7,694
General and administrative expenses	860	767	1,871	1,710
Total costs and expenses	5,853	5,663	11,845	11,395
Operating income	23,135	11,950	38,415	20,932
Other income, net	31	132	161	273
Net earnings	$ 23,166	$ 12,082	$ 38,576	$ 21,205
Allocation of net earnings:				
General partner	$ 662	$ 341	$ 1,125	$ 601
Unitholders	$ 22,504	$ 11,741	$ 37,451	$ 20,604
Net earnings per common unit (basic and diluted)	$ 0.80	$ 0.42	$ 1.33	$ 0.73

Weighted average common units outstanding	28,240	28,240	28,240	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)

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Net cash provided by operating activities	$ 39,886	$ 27,908
Cash flows (used in) provided by investing activities:		
Proceeds from related party note receivable	-	26
Capital expenditures	(50)	-
Total cash flows (used in) provided by investing activities	(50)	26
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(31,662)	(27,324)
Increase in cash and cash equivalents	8,174	610
Cash and cash equivalents at beginning of period	15,001	13,927
Cash and cash equivalents at end of period	$ 23,175	$ 14,537

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.

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 on January 7, 2008, the plaintiff filed an appeal. On March 3, 2008, the appeal was dismissed by the Oklahoma Supreme Court pending disposition by the District Court of unresolved related claims. On June 23, 2008, the operating partnership dismissed, without prejudice, its counterclaim. Other unresolved claims are still pending at the District 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. Distributions to Holders of Common Units: Since commencing operations on January 31, 2003, unitholder cash distributions per common unit have been:

	Per Unit Amount					
	2003	2004	2005	2006	2007	2008
	$0.206469	$0.415634	$0.481242	$0.729852	$0.461146	$0.572300

First quarter						
Second quarter	$0.458087	$0.415315	$0.514542	$0.778120	$0.473745	$0.769206
Third quarter	$0.422674	$0.476196	$0.577287	$0.516082	$0.560502	
Fourth quarter	$0.391066	$0.426076	$0.805543	$0.478596	$0.514625	

Distributions beginning with the third quarter of 2004 were paid on 28,240,431 units; previous distributions were paid on 27,040,431 units. Fourth quarter distributions shown above are paid in the first calendar quarter of the following year. Our partnership agreement requires the next cash distribution to be paid by November 15, 2008.

4. New Accounting Pronouncements: In September 2006, the Financial Accounting Standards Board issued Statement No. 157, “Fair Value Measurements” (“SFAS 157”), which defines fair value, establishes a framework to measure assets and liabilities, and expands disclosures about fair value measurements. This statement applies whenever other statements require or permit assets or liabilities to be measured at fair value. SFAS 157 is effective for fiscal years beginning after November 15, 2007, except for nonfinancial assets and liabilities that are recognized or disclosed at fair value in financial statements on a recurring basis, for which application has been deferred for one year. We adopted SFAS 157 in the first quarter of 2008 with no material impact on our consolidated 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 573 counties and parishes in 25 states.

Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner, holds working 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 in property groups made up of four NPIs created when we commenced operations in 2003. We refer to our net profits overriding royalty interest in these property groups as the Net Profits Interests. We currently receive monthly payments equaling 96.97% of the preceding month’s net profits actually realized by the operating partnership from three of the property groups. 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, 2008, 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 cash receipts and disbursements attributable to the Minerals NPI:

Minerals NPI Cash Basis Results
(in Thousands)

	Cumulative Total at 12/31/07	Six Months Ended 6/30/08	Cumulative Total at 6/30/08
Cash received for revenue	$ 8,200	$ 2,253	$ 10,453
Cash paid for operating costs	1,373	326	1,699
	6,946	2,404	9,350

Cash paid for development costs						
Net cash paid	$	(119)	$	(477)	$	(596)
Cumulative NPI deficit	$	(119)	$	(596)	$	(596)

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. Amounts in the above table include budgeted capital expenditures of $1,152,000 at June 30, 2008. The amounts also 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, 2008 as compared to Three and Six Months Ended June 30, 2007

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:	2008	2007	2008	2008	2007
Royalty properties gas sales (mmcf)	872	838	992	1,864	1,696
Royalty properties oil sales (mbbls)	80	79	72	152	153
Net profits interests gas sales (mmcf)	974	1,035	987	1,961	2,051
Net profits interests oil sales (mbbls)	3	4	4	7	8
Accrual basis weighted average sales price:					
Royalty properties gas sales ($/mcf)	$ 10.73	$ 7.71	$ 7.96	$ 9.26	$ 7.15
Royalty properties oil sales ($/bbl)	$ 116.43	$ 59.13	$ 94.88	$ 106.14	$ 56.58
Net profits interests gas sales ($/mcf)	$ 11.90	$ 7.82	$ 8.04	$ 9.96	$ 7.28
Net profits interests oil sales ($/bbl)	$ 116.81	$ 56.62	$ 80.10	$ 98.18	$ 51.66
Accrual basis production costs deducted under the net profits interests ($/mcfe) (1)	$ 1.94	$ 2.06	$ 1.99	$ 1.96	$ 2.07

(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 virtually unchanged at 79 mbbls in 2007 compared to 80 mbbls in 2008. Oil sales volumes attributable to our Royalty Properties during the first six months were also virtually unchanged at 153 mbbls in 2007 compared to 152 mbbls in 2008. Natural gas sales volumes attributable to our Royalty Properties during the second quarter increased 4.1% from 838 mmcf in 2007 to 872 mmcf in 2008. Natural gas sales volumes attributable to our Royalty Properties during the first six months increased 9.9% from 1,696 in 2007 to 1,864 mmcf in 2008. The increases in natural gas sales volumes were primarily attributable to weather-related problems that negatively affected production in the first quarter and portions of the second quarter of 2007.

Oil sales volumes attributable to our Net Profits Interests during the second quarter and first six months of 2008 were virtually unchanged when compared to the same periods of 2007. Natural gas sales volumes attributable to our Net Profits Interests during the second quarter and first six months of 2008 decreased from the same periods of 2007. Second quarter sales of 974 mmcf during 2008 were 5.9% less than 1,035 mmcf during 2007. First six month sales of 1,961 mmcf during 2008 were 4.4% less than 2,051 mmcf during 2007. 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.

Weighted average oil sales prices attributable to our interest in Royalty Properties increased 96.9% from $59.13/bbl during the second quarter of 2007 to $116.43/bbl during the second quarter of 2008 and increased 87.6% from $56.58/bbl during the first six months of 2007 to $106.14/bbl during the same period of 2008. Second quarter weighted average natural gas sales prices from Royalty Properties increased 39.2% from $7.71/mcf during 2007 to $10.73/mcf during 2008. The six months ended June 30 weighted average Royalty Properties natural gas sales prices increased 29.5% from $7.15/mcf during 2007 to $9.26/mcf during 2008. Both oil and natural gas price changes resulted from changing market conditions.

Second quarter weighted average oil sales prices from the Net Profits Interests’ properties increased 106.3% from $56.62/bbl in 2007 to $116.81/bbl in 2008. The first six months Net Profits Interests’ oil sales prices increased 90.1% from $51.66/bbl in 2007 to $98.18/bbl in 2008. Changing market conditions resulted in increased oil prices. Weighted average natural gas sales prices attributable to the Net Profits Interests increased during the second quarter of 2008 compared to the same period of 2007 and increased from the first six months of 2007 to the same period of 2008. Second quarter natural gas sales prices of $11.90/mcf in 2008 were 52.2% more than $7.82/mcf in 2007. The six months ended June 30, 2008 natural gas prices increased 36.8% to $9.96/mcf from $7.28/mcf in the same period of 2007. Natural gas sales price increases during the three and six month periods resulted from changing market conditions plus a natural gas liquid 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. We will accrue such payment at the end of each annual contract period. Only immaterial amounts were received prior to 2007.

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 2008 second quarter totaled $14,842,000. These receipts generally reflect oil sales during March through May 2008 and natural gas sales during February through April 2008. The weighted average indicated prices for oil and natural gas sales during the 2008 second quarter attributable to the Royalty Properties were $103.92/bbl and $8.54/mcf, respectively.

Cash receipts attributable to our Net Profits Interests during the 2008 second quarter totaled $8,619,000. These receipts reflect oil and natural gas sales from the properties underlying the Net Profits Interests generally during February through April 2008 and include a payment received by the operating partnership during May 2008 attributable to 2007 natural gas liquids in the Oklahoma Guymon-Hugoton field, which increased the weighted average price by $1.90/mcf. The weighted average indicated prices received during the 2008 second quarter for oil and natural gas sales, including the natural gas liquids payment, were $94.16/bbl and $10.58/mcf, respectively.

Our second quarter net operating revenues increased 64.6% from $17,613,000 during 2007 to $28,988,000 during 2008. Net operating revenues for the first six months of 2008 increased 55.5% from $32,327,000 during 2007 to $50,260,000 during 2008. Both the quarterly and six month increase resulted from increased gas and oil sales prices including a 2007 natural gas liquid payment received during the second quarter 2008.

Costs and expenses increased 3.4% from $5,663,000 during the second quarter of 2007 to $5,853,000 during the second quarter of 2008, while six months ended June 30 costs and expenses increased 3.9% from $11,395,000 during 2007 to $11,845,000 during 2008. Such increases primarily resulted from increased production tax on higher operating revenues.

Depletion and amortization decreased 5.8% during the second quarter ended June 30, 2008 and 3.3% during the six months ended June 30, 2008 when compared to the same periods of 2007. The decreases from $3,873,000 and $7,694,000 during the second quarter and six months ended June 30, 2007, respectively, to $3,648,000 and $7,438,000 during the same periods of 2008 respectively, resulted from a lower depletable base due to effects of previous depletion and upward revisions in oil and natural gas reserve estimates at 2007 year end.

Second quarter net earnings allocable to common units increased 91.7% from $11,741,000 during 2007 to $22,504,000 during 2008. First six months common unit net earnings increased 81.8% from $20,604,000 during 2007 to $37,451,000 during 2008. The 2008 increase from the second quarter 2007 and the first six months 2007 net earnings is primarily the result of increased oil and natural gas sales prices.

Net cash provided by operating activities increased 60.4% from $14,143,000 during the second quarter of 2007 to $22,683,000 during the second quarter of 2008 and increased 42.9% from $27,908,000 for the first six months during 2007 to $39,886,000 during the same period of 2008. Increases in both periods are primarily due to increased oil and natural gas sales prices along with abnormal natural gas liquid payments. See discussion above on net operating revenues for more details.

We received cash payments in the amount of $268,000 from various sources during the second quarter of 2008 including lease bonuses attributable to 17 consummated leases and pooling elections located in 8 counties and parishes in two states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to $500/acre.

We received division orders for, or otherwise identified, 122 new wells completed on our Royalty Properties and Net Profits Interests located in 49 counties and parishes in eight states during the second quarter of 2008. The operating partnership elected to participate in 14 wells to be drilled on our Net Profits Interests located in five 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 following table.

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

	County			DMLP	DMOLP		Test Rates per day	
State	/Parish	Operator	Well Name	NRI(2)	WI(1)	NRI(2)	Gas, mcf	Oil, bbls
AR	Logan	Highland Oil & Gas	Gregory #1	0.000%	6.250%	6.250%	1,025	--
LA	Bienville	El Paso E & P Co.	Poole A #3 Alt	0.878%	0.000%	0.000%	3,182	7
LA	De Soto	Comstock Oil & Gas	Crews, Lena #3 Alt	2.734%	0.000%	0.000%	2,041	--
ND	Mountrail	EOG Resources	Risan #1-34A	0.000%	0.000%	1.046%	308	817
OK	Ellis	Crusader Energy	Raiders #4-27H	0.000%	3.750%	9.063%	732	192
TX	Hidalgo	El Paso E & P Co.	Coates A #38	6.423%	0.000%	0.000%	1,821	--
TX	Starr	Ascent Operating	Garza Hitchcock #13	2.653%	0.000%	0.000%	2,260	--
TX	Starr	El Paso E & P Co.	Guerra – USA GU “D” #15	8.194%	0.000%	0.000%	2,088	--
TX	Val Verde	TEMA Oil and Gas Co.	Meadows #1107	0.000%	12.383%	12.383%	391	--
TX	Val Verde	Noble Energy	R N Byers #2305	3.125%	0.000%	0.000%	1,362	18

(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. Ninety-four wells have been permitted on the lands as of June 30, 2008. 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 wells completed 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
Conway	Petrohawk	Morrow 8-15 #1-30H	1.875%	5.000%	5.000%	516
Conway	SEECO	Green Bay Packaging 9-15 #1-19H	0.059%	0.000%	0.000%	3,216

Conway	SEECO	Green Bay Packaging 9-15 #2-19H	0.059%	0.000%	0.000%	5,453
Conway	SEECO	Deltic Timber 9-16 #1-25H	1.563%	1.250%	0.938%	1,629
Conway	SEECO	Deltic Timber 9-16 #2-25H	1.563%	1.250%	0.938%	1,207
Conway	SEECO	Jerome Carr 9-15 #3-31H	2.189%	3.796%	2.847%	3,847
Faulkner	Petrohawk	Jolly 8-12 #1-9H	0.977%	0.000%	0.000%	--
Van Buren	Chesapeake	Douglas Krahn 11-13 #1-5H	0.478%	0.383%	0.287%	204
Van Buren	Petrohawk	Lewis 11-13 #3-30H	0.684%	0.000%	0.000%	513
Van Buren	Petrohawk	Smith 11-13 #1-30H	0.684%	0.000%	0.000%	--
Van Buren	SEECO	Howard Family Trust 10-12 #1-9H	2.344%	4.375%	3.281%	2,574
Van Buren	SEECO	Breeding 9-13 #2-25H	0.781%	0.000%	0.000%	2,738
Van Buren	SEECO	Breeding 9-13 #1-25H	0.781%	0.000%	0.000%	2,601
Van Buren	SEECO	Crow 10-15 #4-28H33	0.000%	5.276%	5.259%	2,882
Van Buren	SEECO	Handy 10-12 #2-18H	2.656%	5.000%	3.750%	3,328

(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.

Set forth below is a summary of all permitting, drilling and completion activity through June 30, 2008 for wells in which we have a royalty or net profits interest. This includes wells subject to the Minerals NPI, which is currently in a deficit status.

	2004	2005	2006	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Q2 2008	Total
New Well Permits	1	2	11	4	9	12	11	18	26	94
Wells Spud	0	1	9	4	7	9	13	12	18	73
Wells Completed	0	1	5	2	4	8	9	10	15	54
Wells in Pay Status (1)	0	1	0	2	3	3	6	4	7	26

(1) 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 $303,000 in the first quarter from 11 wells and $369,000 in the second quarter from 18 wells. Net cash receipts for the Minerals NPI Properties attributable to interests in these lands totaled $263,000 and $338,000 in the first and second quarters, respectively.

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 circulated a Request for Proposal to industry participants in May, 2008 to solicit expressions of interest to lease or jointly develop our interests in this area. As of July 29, 2008, we have not received any proposals. We will continue to monitor industry activity and encourage dialogue with industry participants to determine the proper course of action regarding our interests.

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 3 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 has drilled and completed a well in the Oklahoma Council Grove formation at a cost of approximately $440,000. The well was connected to a gas sales pipeline during the second quarter of 2008 and is currently producing 75 mcf per day.

The operating partnership plans to continue its efforts to increase production in Oklahoma with techniques that may include fracture treating, deepening, recompleting, and replacing existing wells. Based on prior efforts, 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 Net Profits Interests 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. The operating partnership believes it now has sufficient field compression and permits for vacuum operation for the foreseeable future. These capital and operating costs are reflected in the Net Profits Interests payments we receive from the operating partnership.

In 1998, Oklahoma regulations removed production quantity restrictions in the Guymon-Hugoton field and did not address efforts by third parties to persuade Oklahoma to permit infill drilling in the Guymon-Hugoton field. Infill drilling could require considerable capital expenditures. The outcome and the cost of such activities are unpredictable and could influence the amount we receive from the Net Profits Interests.

Liquidity and Working Capital

Cash and cash equivalents totaled $23,175,000 at June 30, 2008 and $15,001,000 at December 31, 2007.

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, 2008 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

None.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

(a) We held our Annual Unitholders meeting on Tuesday, May 13, 2008 in Dallas, Texas.

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

(c) The only matter voted on at the meeting was the election of the three nominees to the Board of Managers. Out of the 28,240,431 units issued and outstanding and entitled to vote at the meeting, 24,985,145 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	24,741,013	244,132	3,255,286
C.W. “Bill” Russell	24,819,105	166,040	3,255,286
Ronald P. Trout	24,825,281	159,864	3,255,286

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 7, 2008

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

Date: August 7, 2008

INDEX TO EXHIBITS

Number	Description
3.1	Certificate of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.1 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.2	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.2 to Dorchester Minerals' Report on Form 10-K filed for the year ended December 31, 2002)
3.3	Certificate of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.4	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.5	Certificate of Formation of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.7 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.6	Amended and Restated Limited Liability Company Agreement of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.6 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.7	Certificate of Formation of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.8	Limited Liability Company Agreement of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.9	Certificate of Limited Partnership of Dorchester Minerals Operating LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.10	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Operating LP. (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.11	Certificate of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.12	Agreement of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)

3.13	Certificate of Incorporation of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.13 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.14	Bylaws of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.14 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.15	Certificate of Limited Partnership of Dorchester Minerals Acquisition LP (incorporated by reference to Exhibit 3.15 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2004)
3.16	Agreement of Limited Partnership of Dorchester Minerals Acquisition LP (incorporated by reference to Exhibit 3.16 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004)
3.17	Certificate of Incorporation of Dorchester Minerals Acquisition GP, Inc. (incorporated by reference to Exhibit 3.17 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004)
3.18	Bylaws of Dorchester Minerals Acquisition GP, Inc. (incorporated by reference to Exhibit 3.18 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004)
31.1	Certification of Chief Executive Officer of the Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
31.2	Certification of Chief Financial Officer of the Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
32.1	Certification of Chief Executive Officer of the Partnership pursuant to 18 U.S.C. Sec. 1350
32.2	Certification of Chief Financial Officer of the Partnership pursuant to 18 U.S.C. Sec. 1350 (contained within Exhibit 32.1 hereto)