DORCHESTER MINERALS LP
Form 10-Q
November 06, 2006

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 September 30, 2006
Commission file number 000-50175

DORCHESTER MINERALS, L.P.
(Exact name of Registrant as specified in its charter)

Delaware	81-0551518
(State or other jurisdiction of Incorporation or organization)	(I.R.S. Employer Identification No.)

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

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

None
Former name, former address and former fiscal
year, if changed since last report

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

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

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

As of November 6, 2006, 28,240,431 common units of partnership interest were outstanding.

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DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

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

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

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

PART I

ITEM 1. FINANCIAL INFORMATION

See attached financial statements on the following pages.

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

CONDENSED BALANCE SHEETS
(Dollars in Thousands)

	September 30, 2006	December 31, 2005
ASSETS	(unaudited)	
Current assets:		
Cash and cash equivalents	$ 16,118	$ 23,389
Trade receivables	6,304	7,615
Net profits interests receivable - related party	3,901	6,996
Current portion of note receivable - related party	50	50
Prepaid expenses	12	22
Total current assets	26,385	38,072
Note receivable - related party less current portion	17	55
Other non-current assets	19	19
Total	36	74
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method):	291,875	291,875
Less accumulated full cost depletion	143,914	129,643
Total	147,961	162,232
Leasehold improvements	512	512
Less accumulated amortization	97	60
Total	415	452
Net property and leasehold improvements	148,376	162,684
Total assets	$174,797	$200,830
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities		
Accounts payable and other current liabilities	$ 1,606	$ 580
Current portion of deferred rent incentive	39	39
Total current liabilities	1,645	619
Deferred rent incentive less current portion	297	326
Total liabilities	1,942	945
Commitments and contingencies		
Partnership capital:		
General partner	6,961	7,663
Unitholders	165,894	192,222
Total partnership capital	172,855	199,885
Total liabilities and partnership capital	$174,797	$200,830

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

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

CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands except Earnings per Unit)
(Unaudited)

	Three Months Ended September 30,		Six Months Ended September 30,	
	2006	2005	2006	2005
Operating revenues:				
Net profits interests................	$ 5,125	$ 8,755	$17,003	$ 21,329
Royalties............................	11,481	14,442	35,245	33,077
Lease bonus..........................	281	456	7,017	606
Other................................	10	17	39	47
Total operating revenues.............	16,897	23,670	59,304	55,059
Cost and expenses:				
Operating, including production taxes	1,315	1,028	3,134	2,501
Depletion and amortization...........	4,787	5,659	14,308	16,161
General and administrative expenses...	733	618	2,337	2,085
Total costs and expenses..................	6,835	7,305	19,779	20,747
Operating income	10,062	16,365	39,525	34,312
Other income (expense), net:				
Investment income....................	171	95	557	219
Other income (expense), net..........	159	(57)	159	(61)
Total other income (expense), net.....	330	38	716	158
Net earnings	$10,392	$ 16,403	$40,241	$ 34,470
Allocation of net earnings:				
General partner......................	$ 310	$ 461	$ 1,234	$ 946
Unitholders..........................	$10,082	$ 15,942	$39,007	$ 33,524
Net earnings per common unit (basic and diluted)...............................	$ 0.36	$ 0.57	$ 1.38	$ 1.19
Wtd. avg. common units outstanding	28,240	28,240	28,240	28,240

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

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

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

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Net cash provided by operating activities	$ 59,962	$ 46,487
Cash flows used in investing activities:		
Proceeds from related party note receivable	38	39
Capital expenditures	-	(109)
Total cash flows provided by (used in) investing activities	38	(70)
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(67,271)	(41,256)
Increase (decrease) in cash and cash equivalents	(7,271)	5,161
Cash and cash equivalents at January 1,	23,389	12,365
Cash and cash equivalents at September 30,	$ 16,118	$ 17,526

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

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

NOTES TO THE CONDENSED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation: Dorchester Minerals, L.P. is a publicly traded Delaware limited partnership that commenced operations on January 31, 2003, upon the combination of Dorchester Hugoton, Ltd., which was a publicly traded Texas limited partnership, and Republic Royalty Company and Spinnaker Royalty Company, L.P., both of which were privately held Texas partnerships.

The condensed financial statements reflect all adjustments (consisting only of normal and recurring adjustments unless indicated otherwise) that are, in the opinion of management, necessary for the fair presentation of our Partnership's financial position and operating results for the interim period. Interim period results are not necessarily indicative of the results for the calendar year. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information. Per-unit information is calculated by dividing the income applicable to holders of our Partnership's common units by the weighted average number of units outstanding. Certain amounts in the 2005 financial statements have been reclassified to conform with the 2006 presentation. Such reclassifications did not impact net income, or total assets, or total liabilities.

2. Contingencies: In January 2002, some individuals and an association called Rural Residents for Natural Gas Rights sued Dorchester Hugoton, Ltd.,

along with several other operators in Texas County, Oklahoma. Dorchester Minerals Operating LP 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 our Partnership. The plaintiffs consist primarily of Texas County, Oklahoma residents who, in residences located on leases use natural gas from gas wells located on the same leases, at their own risk, free of cost. The plaintiffs seek declaration that their domestic gas use is not limited to stoves and inside lights and is not limited to a principal dwelling as provided in the oil and gas leases entered into in the 1930s to the 1950s. Plaintiffs' claims against defendants include failure to prudently operate wells, violation of rights to free domestic gas, and fraud. Plaintiffs also seek certification of class action against defendants. On October 1, 2004, the plaintiffs severed claims against Dorchester Minerals Operating LP regarding royalty underpayments. Dorchester Minerals Operating LP believes plaintiffs' claims, including severed claims, are completely without merit. Based upon past measurements of such domestic gas usage, Dorchester Minerals Operating LP believes the domestic gas damages sought by plaintiffs to be minimal. An adverse decision could reduce amounts our Partnership receives from the Net Profits Interests.

Our Partnership and Dorchester Minerals Operating LP are involved in other legal and/or administrative proceedings arising in the ordinary course of their businesses, none of which have predictable outcomes and none of which are believed to have any significant effect on financial position or operating results.

3. Distributions to Holders of Common Units: Since our Partnership's combination on January 31, 2003, unitholder cash distributions per common unit have been or will be:

Year	Quarter	Record Date	Payment Date	Amount
2003	1st (partial)	April 28, 2003	May 8, 2003	$0.206469
2003	2nd	July 28, 2003	August 7, 2003	$0.458087
2003	3rd	October 31, 2003	November 10, 2003	$0.422674
2003	4th	January 26, 2004	February 5, 2004	$0.391066
2004	1st	April 30, 2004	May 10, 2004	$0.415634
2004	2nd	July 26, 2004	August 5, 2004	$0.415315
2004	3rd	October 25, 2004	November 4, 2004	$0.476196
2004	4th	February 1, 2005	February 11, 2005	$0.426076
2005	1st	April 29, 2005	May 9, 2005	$0.481242
2005	2nd	July 25, 2005	August 4, 2005	$0.514542
2005	3rd	October 24, 2005	November 3, 2005	$0.577287
2005	4th	January 30, 2006	February 9, 2006	$0.805543
2006	1st	May 1, 2006	May 11, 2006	$0.729852
2006	2nd	July 24, 2006	August 3, 2006	$0.778120
2006	3rd	October 23, 2006	November 3, 2006	$0.516082

Distributions beginning with the third quarter of 2004 were paid on 28,240,431 units; previous distributions were paid on 27,040,431 units. Our partnership agreement requires the next cash distribution to be paid by February 14, 2007.

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

Overview

We own producing and nonproducing mineral, royalty, overriding royalty, net profits and leasehold interests. We refer to these interests as the Royalty Properties. We currently own Royalty Properties in 573 counties and parishes in

25 states.

Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner, holds the working interest properties previously owned by Dorchester Hugoton and a minor portion of mineral, royalty and working interest properties previously owned by Republic and Spinnaker. We refer to Dorchester Minerals Operating LP as the "operating partnership." We directly and indirectly own a 96.97% net profits overriding royalty interest in these properties. We refer to our net profits overriding royalty interest in these properties as the Net Profits Interests. We receive monthly payments equaling 96.97% of the net profits actually realized by the operating partnership from these properties in the preceding month.

In accordance with our partnership agreement we have the continuing right to create additional net profits interests by transferring properties to the operating partnership subject to the reservation of a Net Profits Interest identical to the Net Profits Interests created upon our formation. Two such interests, called the 2003/2004/2005 NPI and the 2006 NPI, resulted from transferring various properties to the operating partnership subject to a Net Profits Interest. As of September 30, 2006 cumulative costs and expenses, which include an interest equivalent, totaled $4,111,000 attributable to the 2003/2004/2005 NPI properties and exceeded cumulative revenues by $115,000, an amount which we refer to as the 2003/2004/2005 NPI deficit. The 2006 NPI deficit was $85,000, with no revenues received. Our financial statements do not reflect activity attributable to properties subject to Net Profits Interests that are in a deficit status, except for temporary deficits. Consequently, revenues, expenses, production sales volumes and prices set forth herein do not reflect amounts attributable to the 2003/2004/2005 NPI or the 2006 NPI properties. However, information concerning acreage owned and drilling activity attributable to these properties is included herein.

Commodity Price Risks

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

Results of Operations

Three and Nine Months Ended September 30, 2006 as compared to Three and Nine Months Ended September 30, 2005

Normally, our period-to-period changes in net earnings and cash flows from operating activities are principally determined by changes in crude oil and natural gas sales volumes and prices. Our portion of oil and natural gas sales and weighted average prices were:

	Three Months Ended			Nine Months Ended	
	September 30,		June 30,	September 30,	
Accrual Basis Sales Volumes:	2006	2005	2006	2006	2005
Net Profits Interests Gas Sales (mmcf)	1,128	1,228	1,140	3,394	3,666
Net Profits Interests Oil Sales (mbbls)	4	2	4	11	7
Royalty Properties Gas Sales (mmcf)	1,018	1,097	1,014	2,997	2,961
Royalty Properties Oil Sales (mbbls)	84	94	84	253	264
Weighted Average Sales Price:					
Net Profits Interests Gas Sales ($/mcf)	$ 5.87	$ 8.49	$ 5.80	$ 6.36	$ 7.10

Net Profits Interests Oil Sales ($/bbl)	$63.25	$57.20	$53.51	$55.04	$48.84
Royalty Properties Gas Sales ($/mcf)	$ 6.09	$ 8.22	$ 6.18	$ 6.54	$ 6.71
Royalty Properties Oil Sales ($/bbl)	$62.83	$57.78	$65.86	$61.77	$50.04
Production Costs Deducted Under the Net Profits Interests ($/mcfe) (1)	$ 1.61	$ 1.48	$ 1.36	$ 1.57	$ 1.40

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

Oil sales volumes attributable to our Royalty Properties during the third quarter decreased 10.6% from 94 mbbls in 2005 to 84 mbbls in 2006. Oil sales volumes attributable to our Royalty Properties during the first nine months decreased 4.2% from 264 mbbls in 2005 to 253 mbbls in 2006. Natural gas sales volumes attributable to our Royalty Properties during the third quarter decreased 7.2% from 1,097 mmcf in 2005 to 1,018 mmcf in 2006. Natural gas sales volumes attributable to our Royalty Properties during the first nine months increased 1.2% from 2,961 in 2005 to 2,997 mmcf in 2006. The decreases in oil and natural gas sales volumes are primarily attributable to new wells drilled on the Royalty Properties in late 2004 and early 2005. As previously reported, these wells have exhibited significant production declines after initially producing at anomalously high rates. Year to date natural gas sales volumes attributable to our Royalty Properties were positively affected by prior period adjustments received in the second and third quarter. Oil and natural gas sales volumes attributable to our Royalty Properties during the third quarter were essentially unchanged from second quarter levels.

Oil sales volumes attributable to our Net Profits Interests during the third quarter and first nine months of 2006 increased from 7 to 11 mbbls respectively when compared to the same periods of 2005 as a result of additional wells being developed on existing Net Profits Interests' properties. Natural gas sales volumes attributable to our Net Profits Interests during the third quarter and first nine months of 2006 decreased from the same periods of 2005. Third quarter sales of 1,128 mmcf during 2006 were 8.1% less than 1,2228 mmcf during 2005. First nine months sales of 3,394 mmcf during 2006 were 7.4% less than 3,666 mmcf during 2005. The natural gas sales volume decreases were a result of natural reservoir decline. Production sales volumes and prices from the 2003/2004/2005 NPI and the 2006 NPI properties are excluded from the above table. See "Overview" above.

Weighted average oil sales prices attributable to our interest in Royalty Properties increased 8.7% from $57.78/bbl during the third quarter of 2005 to $62.83/bbl during the third quarter of 2006 and 23.4% from $50.04/bbl during the first nine months of 2005 to $61.77/bbl during the first nine months of 2006. The third quarter weighted average natural gas sales prices from Royalty Properties were down 25.9% from $8.22/mcf during 2005 to $6.09/mcf during 2006. The nine months ended September 30 weighted average natural gas sales prices decreased 2.5% from $6.71/mcf during 2005 to $6.54/mcf during 2006. Both oil and natural gas price changes resulted from changing market conditions.

Third quarter weighted average oil sales prices from the Net Profits Interests' properties increased 10.6% from $57.20/bbl in 2005 to $63.25/bbl in 2006. The first nine months Net Profits Interests oil sales prices increased 12.7% from $48.84/bbl in 2005 to $55.04/bbl in 2006. Weighted average natural gas sales prices attributable to the Net Profits Interests decreased during the third quarter and the first nine months of 2006 compared to the same periods of 2005. Third quarter natural gas sales prices of $5.87/mcf in 2006 were 30.9% less than $8.49/mcf in 2005. The nine months ended September 30, 2006 natural gas prices decreased 10.4% to $6.36/mcf from $7.10/mcf in the same period of 2005. Changing market conditions resulted in increased oil prices and decreased natural gas sales prices.

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

Cash receipts attributable to our Net Profits Interests during the 2006 third quarter totaled $5,069,000. These receipts generally reflect oil and gas sales from the properties underlying the Net Profits Interests during May through July 2006. The weighted average indicated prices for oil and gas sales during the 2006 third quarter attributable to the Net Profits Interests were $60.08/bbl and $5.70/mcf, respectively.

Cash receipts attributable to our Royalty Properties during the 2006 third quarter totaled $10,390,000. These receipts generally reflect oil sales during June through August 2006 and gas sales during May through July 2006. The weighted average indicated prices for oil and gas sales during the 2006 third quarter attributable to the Royalty Properties were $64.37/bbl and $6.07/mcf, respectively.

Our third quarter net operating revenues decreased 28.6% from $23,670,000 during 2005 to $16,897,000 during 2006 primarily as a result of decreased gas sales prices and decreased gas and oil sales volumes partially offset by increased oil sales prices. Net operating revenues for the first nine months of 2006 increased 7.7% from $55,059,000 during 2005 to $59,304,000. The nine-month changes resulted primarily from essentially unchanged royalty natural gas sales volumes and prices, decreased NPI gas volumes and prices and increased oil sales prices offset by decreased oil sales volumes. Year to date net operating revenues during 2006 included lease bonus payments of $6,151,000 attributable to the previously announced Arkansas lease transaction.

Costs and expenses decreased 6.4% from $7,305,000 during the third quarter of 2005 to $6,835,000 during the third quarter of 2006, while the nine months ended September 30 costs and expenses decreased 4.7% from $20,747,000 during 2005 to $19,779,000 during 2006. Such decreases primarily resulted from decreased depletion and amortization, offset by increased ad valorem taxes on royalty properties as a result of increased taxing authority valuations due to higher product prices at 2005 year end.

Investment income increased from $95,000 in the third quarter of 2005 to $171,000 in the third quarter of 2006, and increased from $219,000 in the first nine months of 2005 to $557,000 in the first nine months of 2006, due to increased cash flows and higher interest rates during the first nine months of 2006. We received $159,000 in other income related to class action litigation settlements during the third quarter of 2006.

Depletion and amortization decreased 15.4% during the third quarter ended September 30, 2006 and 11.5% during the nine months ended September 30, 2006 when compared to the same periods of 2005. The decreases from $5,659,000 and $16,161,000 during the third quarter and nine months ended September 30, 2005 respectively, to $4,787,000 and $14,308,000 during the same periods of 2006 respectively, resulted from a lower depletable base due to effects of previous depletion.

We received cash payments in the amount of $604,000 from various sources during the third quarter of 2006 including lease bonuses attributable to 12 consummated leases and pooling elections located in six counties and parishes in four states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to $625/acre.

We received division orders, or otherwise identified, 98 new wells completed on our Royalty Properties and Net Profit Interests located in 49 counties and parishes in 11 states during the third quarter of 2006. The operating partnership elected to participate in seven wells to be drilled on our Net Profits Interests located in six counties in four 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 and discussion:

State	County/ Parish	Operator	Well Name	Ownership		Test Rates, per day	
				WI(1)	NRI(1)	Gas,mcf	Oil,bbls
Royalty Properties							
TX	Jackson	Neumin Prod.	Kubecka GU #1	--	1.4%	4,000	400
TX	Wheeler	Devon	Effie Hayes 18-3	--	3.1%	3,004	17
OK	Love	Finley Res.	W.Enville WMA 1-31	--	2.4%	1,230	334
TX	Panola	Chesapeake	Bill Powers A #5	--	5.5%	1,116	37
TX	Upton	Pure Res.	Bloxom A #3	--	0.1%	3,351	364
TX	Austin	Jamex	Beckendorff GU No.2	--	1.8%	2,564	12
Net Profits Interests							
MT	Richland	Continental	Carda 2-28	6.3%	5.9%	451	670
OK	Ellis	Crusader	Raiders 1-27	3.8%	9.1%	640	71
OK	Ellis	Crusader	Raiders 2-27H	3.8%	9.1%	--	333
AR	Van Buren	SEECO	Russell 2-33H	6.3%	6.3%	866	--
OK	Grady	Ward Pet.	McCasland Farms 1-18	0.8%	0.8%	2,122	32

(1) WI and NRI mean working interest and net revenue interest, respectively.

FAYETTEVILLE SHALE LEASE TRANSACTION - We entered into an agreement on March 30, 2006 to lease our interest in certain lands located in Cleburne, Conway, Faulkner, Franklin, Johnson, Pope, Van Buren, and White Counties, Arkansas. We received a non-refundable payment in the amount of $616,000, which amount was included in the Partnership's first quarter distribution to unitholders. The agreement provided 90 days for title due diligence and documentation.

On June 28, 2006 we leased our average 8.6% mineral interest in 179 sections of land in these eight counties and received additional payments totaling $5,535,000. This amount was included in our second quarter distribution to unitholders. The leases reflect one-fourth royalty and five year primary terms. Assuming the lands are pooled into 640 acre units, we will own an average 2.1% net royalty interest in each well drilled in these sections. In addition to the basic lease terms, we have the option, but not the obligation, to participate for an average 3.5% net working interest in 117 of 179 sections. To date, elections have been made to participate in three wells under this agreement with working interests ranging from 3.8% to 5.0%. A fourth well has been permitted.

We elected not to lease our interest in four sections located in the Gravel Hill Field area of Van Buren County, representing an additional 260 net mineral acres. The Partnership's optional working interest in the leased lands and the unleased mineral interest in the Gravel Hill Field area have been assigned to the operating partnership pursuant to the existing Net Profits Interest agreements. Two horizontal wells have been drilled and completed and one additional well has been proposed on these lands. The SEECO Russell 2-33H well, located in the Gravel Hill Field area of Van Buren County, was completed on August 26 at a reported initial rate of 866 mcfd. The operating partnership has also elected to participate in the Jones 10-16 1-33H with a 3.1% working interest.

Third quarter net earnings allocable to common units decreased 36.8% from $15,942,000 during 2005 to $10,082,000 during 2006. First nine months common unit net earnings increased 16.4% from $33,524,000 during 2005 to $39,007,000 during 2006. The 2006 decrease from third quarter 2005 net earnings is primarily a result of decreased 2006 gas sales prices and, to a lesser extent, decreased gas sales volumes. Third quarter 2006 oil sales price increases from 2005 more than offset oil sales volume decreases from 2005. The 2006 nine-month period compared to the same period in 2005 increased because of lower gas prices and lower gas and oil volumes in 2006 were more than offset by increased 2006 oil sales prices and the $6,151,000 lease bonus payments in 2006 attributable to the previously announced Arkansas lease transaction.

Net cash provided by operating activities decreased 9.1% from $17,005,000 during the third quarter of 2005 to $15,451,000 during the third quarter of 2006. Net cash from operating activities for the first nine months increased 29.0% from $46,487,000 in 2005 to $59,962,000 in 2006. Comparing the 2006 third quarter cash flow to the same period of 2005 shows that the combination of oil price changes and oil volume changes essentially yielded the same cash flow, while gas price declines and gas volume declines reduced overall cash from operations. Gas prices and gas volumes in the 2006 nine-month period were slightly lower than the same period in 2005, while oil prices in 2006 were sharply higher than 2005 with 2006 oil volumes somewhat lower than 2005. These nine-month period volume and price changes when combined with the $6,151,000 lease bonus payments in 2006 attributable to the previously announced Arkansas transaction yielded an increase in 2006 nine-month cash from operations.

Texas Margin Tax

The Texas Legislature recently passed H.B. 3 which is a new tax system, commonly referred to as the Texas margin tax. The Texas margin tax applies to corporations and limited liability companies, general and limited partnerships (unless otherwise exempt), limited liability partnerships, trusts (unless otherwise exempt), business trusts, business associations, professional associations, joint stock companies, holding companies, and joint ventures. The effective date of the Texas margin tax is January 1, 2008, but the tax generally will be imposed on gross revenues generated in 2007 and thereafter.

Limited partnerships that receive at least 90% of their gross income from designated passive sources, including royalties from mineral properties and other non-operated mineral interest income, and do not receive more than 10% of their income from operating an active trade or business, are generally exempt from the Texas margin tax as "passive entities." Our Partnership should meet the requirements for being considered a "passive entity" for Texas margin tax purposes and, therefore, it should be exempt from the Texas margin tax. If exempt from tax at the Partnership level as a passive entity, each unitholder that is considered a taxable entity under the Texas margin tax would generally be required to include its Texas portion of Partnership revenues in its own Texas margin tax computation.

Each unitholder is urged to consult his own tax advisor regarding the requirements for filing state income, franchise and Texas margin tax returns.

Liquidity and Capital Resources

Capital Resources

Our primary sources of capital are our cash flow from the Net Profits Interests and the Royalty Properties. Our only cash requirements are the distributions to our unitholders, the payment of oil and natural gas production and property taxes not otherwise deducted from gross production revenues and general and administrative expenses incurred on our behalf and allocated in accordance with our partnership agreement. Since the distributions to our unitholders are, by definition, determined after the payment of all expenses actually paid by us, the only cash requirements that may create liquidity concerns for us are the payments of expenses. Since most of these expenses vary directly with oil and natural gas prices and sales volumes, we anticipate that sufficient funds will be available at all times for payment of these expenses. See Note 3 of the Notes to the Condensed Financial Statements for the amounts and dates of cash distributions to unitholders.

We are not directly liable for the payment of any exploration, development or production costs. We do not have any transactions, arrangements or other relationships that could materially affect our liquidity or the availability of capital resources. We have not guaranteed the debt of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt.

Pursuant to the terms of our Partnership Agreement, we cannot incur indebtedness, other than trade payables, (i) in excess of $50,000 in the aggregate at any given time or (ii) which would constitute "acquisition indebtedness" (as defined in Section 514 of the Internal Revenue Code of 1986, as amended).

Expenses and Capital Expenditures

During 2006-2008, depending upon rig availability, the operating partnership anticipates drilling possibly two wells in the Oklahoma Council Grove formation, deepening one existing Oklahoma Guymon-Hugoton well, and drilling one replacement Guymon-Hugoton well. The operating partnership does not otherwise currently anticipate drilling additional wells as a working interest owner/operator in the Fort Riley zone or elsewhere in the Oklahoma properties. Successful activities by others in these formations or other developments could prompt a reevaluation of this position. Any such drilling is estimated to cost $350,000 to $450,000 per well while deepening a well should cost less than $150,000. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests.

During the 2006 third quarter, the operating partnership fracture treated one Oklahoma well which improved production from 208 mcf per day to 278 mcf per day while also increasing well shut-in pressure. The cost, including casing leak repair, was $118,000.The operating partnership anticipates continuing additional fracture treating in its Oklahoma properties but is unable to predict the cost as a specific engineering study is required for each fracture treatment. Previous fracture treatments in these properties have cost between $50,000 and $80,000 per well. They did not require casing repairs. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests.

The operating partnership owns and operates 147 wells, with associated pipelines and gas compression and dehydration facilities located in Kansas and Oklahoma Hugoton fields. The operating partnership anticipates gradual increases in expenses as repairs and major maintenance to these facilities becomes more frequent, and anticipates gradual increases in field operating expenses as reservoir pressure declines. The operating partnership does not anticipate incurring significant expense to replace these facilities at this time. These capital and operating costs are reflected in the Net Profit 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 by the operating partnership 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 $16,118,000 at September 30, 2006 and $23,389,000 at December 31, 2005.

Critical Accounting Policies

We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this method, all such costs are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. Oil and gas properties are evaluated using the full cost ceiling test at the end of each quarter.

The discounted present value of our proved oil and natural gas reserves is a major component of the ceiling calculation and requires many subjective judgments. Estimates of reserves are forecasts based on engineering and geological analyses. Different reserve engineers may reach different conclusions as to estimated quantities of natural gas reserves based on the same information. Our reserve estimates are prepared by independent consultants. The passage of time provides more qualitative information regarding reserve estimates, and revisions are made to prior estimates based on updated information. However, there can be no assurance that more significant revisions will not be necessary in the future. Significant downward revisions could result in an impairment representing a non-cash charge to earnings. In addition to the impact on calculation of the ceiling test, estimates of proved reserves are also a major component of the calculation of depletion.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of our reserves are objectively determined. The ceiling test calculation requires use of prices and costs in effect as of the last day of the accounting period, which are generally held constant for the life of the properties. As a result, the present value is not necessarily an indication of the fair value of the reserves. Oil and natural gas prices have historically been volatile and the prevailing prices at any given time may not reflect our Partnership's or the industry's forecast of future prices.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. For example, estimates of uncollected revenues and unpaid expenses from royalties and net profits interests in properties operated by non-affiliated entities are particularly subjective due to inability to gain accurate and timely information. Therefore, actual results could differ from those estimates.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following information provides quantitative and qualitative information about our potential exposures to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices, interest rates and currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Market Risk Related to Oil and Natural Gas Prices

Essentially all of our assets and sources of income are from the Net Profits Interests and the Royalty Properties, which generally entitle us to receive a share of the proceeds based on oil and natural gas production from those properties. Consequently, we are subject to market risk from fluctuations in oil and natural gas prices. Pricing for oil and natural gas production has been volatile and unpredictable for several years. We do not anticipate entering into financial hedging activities intended to reduce our exposure to oil and natural gas price fluctuations.

Absence of Interest Rate and Currency Exchange Rate Risk

We do not anticipate having a credit facility or incurring any debt, other than trade debt. Therefore, we do not expect interest rate risk to be material to us. We do not anticipate engaging in transactions in foreign currencies which could expose us to foreign currency related market risk.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, our principal executive officer and principal financial officer carried out an evaluation of the effectiveness of our disclosure controls and procedures. Based on their evaluation, they have concluded that our disclosure controls and procedures effectively ensure that the information required to be disclosed in the reports we file with the Securities and Exchange Commission is recorded, processed, summarized and reported, within the time periods specified by the Securities and Exchange Commission.

Changes in Internal Controls

There were no changes in our internal controls (as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934) during the quarter ended September 30, 2006 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

None.

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

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

See the attached Index to Exhibits.

SIGNATURES

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

DORCHESTER MINERALS, L.P.

By: Dorchester Minerals Management LP
its General Partner,

By: Dorchester Minerals Management GP LLC,
its General Partner

/s/ William Casey McManemin

William Casey McManemin
Chief Executive Officer

Date: November 6, 2006

/s/ H.C. Allen, Jr.

H.C. Allen, Jr.
Chief Financial Officer

Date: November 6, 2006

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)