Freeman Thomas E
Form 4
December 17, 2010

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL	
OMB Number:	3235-0287
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
Freeman Thomas E

(Last) (First) (Middle)

303 PEACHTREE STREET

(Street)

ATLANTA, GA 30308

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
SUNTRUST BANKS INC [STI]

3. Date of Earliest Transaction (Month/Day/Year)
12/15/2010

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Corp. EVP & Chief Credit Off.

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock								8,687	D	
Common Stock								618.8883	D (1)	
Common Stock								48,675	D (2)	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

number.

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Underlying (Instr. 3 and
								Date Exercisable	Expiration Date	Title
				Code	V	(A)	(D)			
Phantom Stock Units (3)	(3)							(3)	(3)	Common Stock
Phantom Stock Units (4)	(4)	12/15/2010		A		1,329.6167		(4)	(4)	Common Stock
Phantom Stock Units (4)	(4)	12/15/2010		F			19.2795	(4)	(4)	Common Stock
Option (5)	$ 71.03							02/14/2009	02/14/2016	Common Stock
Option (5)	$ 85.06							02/13/2010	02/13/2017	Common Stock
Option (5)	$ 64.58							02/12/2011	02/12/2018	Common Stock
Option (5)	$ 9.06							02/10/2012	02/10/2019	Common Stock
Option (6)	$ 9.06							02/10/2012	02/10/2019	Common Stock

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Freeman Thomas E 303 PEACHTREE STREET ATLANTA, GA 30308			Corp. EVP & Chief Credit Off.	

Signatures

David A. Wisniewski, Attorney-in-Fact for Thomas E. Freeman	12/17/2010
**Signature of Reporting Person	Date

Explanation of Responses:

*	If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).
**	Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).
(1)	Because the stock fund component of the 401(k) is accounted for in unit accounting, the number of share equivalents varies based on the closing price of SunTrust stock on the applicable measurement date.
(2)	Restricted stock granted under SunTrust Banks, Inc. 2004 Stock Plan. Restricted stock agreements contain tax withholding features allowing stock to be withheld to satisfy tax withholding obligations. This plan is exempt under Rule 16(b)-3. Includes 37,600 shares which vest on 02/10/2012.
(3)	The reported phantom stock units were acquired under SunTrust Banks, Inc.'s 401(k) excess benefit plan. These phantom stock units convert to common stock on a one-for-one basis.
(4)	Represents stock units granted under the SunTrust Banks, Inc. 2009 Stock Plan paid as salary. The stock units will be settled in cash one half on March 31, 2011 and one half on March 31, 2012, unless settled earlier due to the executive's death.
(5)	Granted pursuant to the SunTrust Banks, Inc. 2004 Stock Plan.
(6)	Granted pursuant to the SunTrust Banks, Inc. 2009 Stock Plan. This option was granted on February 10, 2009 subject to approval by shareholders of the 2009 Stock Plan. Such plan was approved by Shareholders on April 28, 2009.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. DTH: 1%; VERTICAL-ALIGN: bottom; MARGIN-LEFT: 0pt; BACKGROUND-COLOR: #cceeff" noWrap> $22,476

Cash flows provided by investing activities:

Proceeds from sale of reserves

- 138

Cash flows used in financing activities:

Distributions paid to general partner and unitholders

(19,203

)

(30,413

)

Increase (decrease) in cash and cash equivalents

2,360 (7,799

)

Cash and cash equivalents at beginning of period

7,136 15,912

Cash and cash equivalents at end of period

$9,496 $8,113

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

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1 <u>Basis of Presentation:</u> 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 condensed consolidated financial statements include the accounts of Dorchester Minerals, L.P. and its wholly-owned subsidiaries Dorchester Minerals Oklahoma LP, Dorchester Minerals Oklahoma GP, Inc., Maecenas Minerals LLP, and Dorchester-Maecenas GP LLC. All significant intercompany balances and transactions have been eliminated in consolidation.

The condensed consolidated financial statements reflect all adjustments (consisting only of normal and recurring adjustments unless indicated otherwise) that are, in the opinion of management, necessary for the fair statement 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 income 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 income per unit do not differ. These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership’s annual report on Form 10-K for the year ended December 31, 2015.

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

2 <u>Contingencies:</u> The Partnership and Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner, are involved in 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 <u>Distributions to Holders of Common Units:</u> Unitholder cash distributions per common unit since 2014 have been:

	Per Unit Amount		
	2016	2015	2014
First quarter	$0.147417	$0.306553	$0.496172
Second quarter	$0.257977	$0.167430	$0.490861
Third quarter	$0.252224	$0.194234	$0.447805
Fourth quarter		$0.199076	$0.485780

Each of the foregoing distributions were paid on 30,675,431 units. The third quarter 2016 distribution will be paid on November 10, 2016. Fourth quarter distributions shown above are paid in the first calendar quarter of the following year. Our partnership agreement requires the fourth quarter cash distribution to be paid by February 14, 2017.

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

4 **New Accounting Pronouncements:** In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP.

The standard is effective for annual periods beginning after December 15, 2017, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are currently evaluating the impact of our pending adoption of ASU 2014-09 on our consolidated financial statements and have not yet determined the method by which we will adopt the standard in 2018.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. ASU 2016-02 is effective for public companies for annual periods beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. Companies must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The modified retrospective approach would not require any transition accounting for leases that expired before the earliest comparative period presented. Lessees and lessors may not apply a full retrospective transition approach. The Partnership is currently evaluating ASU 2016-02 to determine the potential impact to its consolidated financial statements and related disclosures.

item 2. **Management's Discussion and Analysis of Financial Condition and Results of Operations**

The following discussion contains forward-looking statements. For a description of limitations inherent in forward-looking statements, see page 1 of this Form 10-Q.

Overview

We own producing and nonproducing mineral, royalty, overriding royalty, net profits and leasehold interests. We refer to these interests as the Royalty Properties. We currently own Royalty Properties in 574 counties and parishes in 25 states.

We own net profits overriding royalty interests (referred to as the Net Profits Interests, or "NPIs") in various properties owned by Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner. We refer to Dorchester Minerals Operating LP as the "operating partnership" or "DMOLP." 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 the event that costs, including budgeted capital expenditures, exceed revenues on a cash basis in a given month for properties subject to a Net Profits Interest, no payment is made and any deficit is accumulated and carried over and reflected in the following month's calculation of net profit.

Each of the five NPIs have previously had cumulative revenue that exceeded cumulative costs, such excess constituting net proceeds on which NPI payments were determined. In the event an NPI has a deficit of cumulative revenue versus cumulative costs, the deficit will be borne solely by the operating partnership.

Prior to initially achieving a cumulative payout status in the third quarter of 2011, the Minerals NPI's activity was not reflected in our consolidated financial statements in accordance with generally accepted accounting principles ("GAAP"). Effective third quarter 2011, our consolidated financial statements reflect activity attributable to the Minerals NPI, and include cash receipts and disbursements and accrued revenues and costs not yet received or paid by the NPI. Our financial statements will continue to reflect such information even if the NPI is in temporary deficit due to capital expenditures. Minerals NPI production volumes and prices are reflected within the consolidated financial statements in accordance with GAAP. Accrued net profits income in the third quarter and nine month period of 2015 from this NPI were zero because accrued cumulative capital costs have exceeded accrued cumulative operating income. In 2016, the accrued net profits income from the Minerals NPI for the third quarter and nine months ended is included in the financial statements.

Prior to the third quarter of 2015, the last payment attributable to the Minerals NPI was declared as of July 31, 2013, at which time cash on hand equaled outstanding capital commitments (resulting in a zero balance, i.e. neither a deficit nor surplus). Since that time, DMOLP has received production revenue, paid operating and capital expenses and made additional capital commitments, resulting in the temporary deficit on a GAAP basis described above.

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Commodity Price Risks

Our profitability is affected by oil and natural gas market prices. Oil and natural gas prices have fluctuated significantly 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 and economic conditions.

Results of Operations

Three and Nine Months Ended September 30, 2016 as compared to Three and Nine Months Ended September 30, 2015

Normally, our period-to-period changes in net income 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 September 30,		Nine Months Ended September 30,	
Accrual basis sales volumes:	2016	2015	2016	2015
Royalty properties gas sales (mmcf)	775	980	2,461	2,704
Royalty properties oil sales (mbbls)	163	127	451	385
NPI gas sales (mmcf)	599	884	1,996	2,483
NPI oil sales (mbbls)	84	156	307	329
Accrual basis weighted average sales price:				
Royalty properties gas sales ($/mcf)	$2.42	$2.40	$1.94	$2.46
Royalty properties oil sales ($/bbl)	$38.72	$37.22	$35.44	$43.47
NPI gas sales ($/mcf)	$2.33	$2.90	$2.07	$2.70
NPI oil sales ($/bbl)	$36.10	$58.43	$33.66	$52.18

Both oil and natural gas sales price changes reflected in the table above resulted from changing market conditions.

Oil sales volumes attributable to our Royalty Properties during the third quarter increased 28% from 127 mbbls in 2015 to 163 mbbls in the same period of 2016. Oil sales volumes attributable to the first nine months of 2015 increased 17% from 385 mbbls to 451 mbbls in the same period of 2016. The increase in volumes during the third quarter and first nine months of 2016 compared to the same periods of 2015 is mainly a result of increased Permian

Basin production partially offset by natural reservoir declines. Natural gas sales volumes attributable to our Royalty Properties during the third quarter decreased 21% from 980 mmcf in 2015 to 775 mmcf in 2016. Natural gas sales volumes during the first nine months decreased 9% from 2,704 mmcf in 2015 to 2,461 mmcf in 2016.The decrease in volumes during the third quarter and first nine months of 2016 compared to the same periods of 2015 is mainly a result of decreased production in the Fayetteville Shale play in addition to lower volumes from suspense release in 2016.

Oil sales volumes attributable to our NPIs during the third quarter and first nine months of 2015 were 156 mbbls and 329 mbbls, respectively, resulting in decreases of 46% and 7% to 84 mbbls and 307 mbbls during the same periods of 2016. The decrease in oil sales volumes is mainly due to lower volumes from suspense release in the third quarter of 2016 compared to 2015. Natural gas sales volumes attributable to our NPIs during the third quarter and first nine months of 2015 were 884 mmcf and 2,483 mmcf, respectively, resulting in decreases of 32% and 20% to 599 mmcf and 1,996 mmcf during the same periods of 2016. The decrease in gas sales volumes is mainly due to natural declines in addition to the effect of the 2016 processing and purchase agreement for our Hugoton properties.

Our third quarter net operating revenues increased 45% from $7,389,000 during 2015 to $10,679,000 during the same period of 2016. Current quarter increases in net profits interest and lease bonus income both contributed to higher net operating revenue in addition to increased royalty revenue. Our first nine months net operating revenues increased 10% from $24,476,000 during 2015 to $26,814,000 during 2016. These increases are primarily a result of increases in lease bonus and net profits interest income in the first nine months of 2016, partially offset by lower oil and natural gas prices.

Third quarter operating costs and expenses increased 52% from $593,000 during 2015 to $902,000 during the same period of 2016. Our first nine months operating costs decreased 16% from $2,604,000 during 2015 to $2,180,000 during the same period of 2016. The decrease between such nine month periods is primarily a result of lower production taxes and lower ad valorem taxes due to lower oil and natural gas sales prices. For the third quarter of 2016 versus the third quarter of 2015, increases in operating costs are primarily due to increased oil sales volumes.

General and administrative expenses of $1,065,000 during the third quarter of 2015 decreased 1% to $1,050,000 during the same period of 2016. General and administrative expenses of $3,488,000 during the first nine months increased 14% compared to $3,967,000 during the same period of 2016. The expense increases are primarily due to outsourcing and enhancement of information technology services and higher legal costs associated with royalty litigation.

Depletion and amortization costs of $3,048,000 during the third quarter of 2015 decreased 32% to $2,080,000 during the same period of 2016. Depletion and amortization costs of $7,854,000 during the first nine months of 2015 decreased 16% compared to $6,571,000 during the same period of 2016. We adjust our depletion each quarter for significant changes in our estimates of oil and natural gas reserves.

Third quarter net income allocable to common units increased 149% from $2,580,000 during 2015 to $6,417,000 during 2016 mainly due to higher royalty income, net profits interest and lease bonus income. Our first nine months net income allocable to common units increased by 34% from $10,125,000 compared to $13,600,000 during the same period of 2016. The increase is mainly due to higher net profits interest and lease bonus income partially offset by lower royalty income due to lower oil and natural gas prices.

Net cash provided by operating activities decreased 4% from $22,476,000 during the first nine months of 2015 to $21,563,000 during the same period of 2016. The change is mainly due to a lower decrease in accounts receivable in 2016 versus the same period in 2015.

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.

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Cash receipts attributable to our Royalty Properties during the third quarter of 2016 totaled approximately $6,500,000. These receipts generally reflect oil sales during June 2016 through August 2016 and natural gas sales during May 2016 through July 2016. The weighted average indicated prices for oil and natural gas sales received during the 2016 third quarter attributable to the Royalty Properties were $39.29/bbl and $1.87/mcf, respectively.

Cash receipts attributable to our NPIs during the third quarter of 2016 totaled approximately $1,900,000. These receipts generally reflect oil and natural gas sales from the properties underlying the NPIs during May 2016 through July 2016. The weighted average indicated prices for oil and natural gas sales received during the 2016 third quarter attributable to our NPIs were $31.81/bbl and $1.88/mcf, respectively.

Liquidity and Capital Resources

Capital Resources

Our primary sources of capital are our cash flows from the NPIs and the Royalty Properties. Our only cash requirements are the distributions to our unitholders, the payment of oil and natural gas production and property taxes not otherwise deducted from gross production revenues and general and administrative expenses incurred on our behalf and allocated in accordance with our partnership agreement. Because 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. Because 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 plans to continuously assess the opportunity to increase production based on prevailing market conditions in Oklahoma with techniques that may include fracture treating, deepening, recompleting, and drilling. Costs vary widely and are not predictable as each effort requires specific engineering. Such activities by the operating partnership could influence the amount we receive from the NPIs.

The operating partnership owns and operates the wells, pipelines and natural gas compression and dehydration facilities located in Oklahoma. The operating partnership does not anticipate incurring significant expense to replace these facilities at this time. These capital and operating costs are reflected in the NPI payments we receive from the operating partnership.

In 1998, Oklahoma regulations removed production quantity restrictions in the Guymon-Hugoton field and did not address efforts by third parties to persuade Oklahoma to permit infill drilling in the Guymon-Hugoton field. Infill drilling could require considerable capital expenditures. The outcome and the cost of such activities are unpredictable and could influence the amount we receive from the NPIs. The operating partnership believes it now has sufficient field compression and permits for vacuum operation for the foreseeable future.

Liquidity and Working Capital

Cash and cash equivalents totaled $9,496,000 at September 30, 2016 and $7,136,000 at December 31, 2015.

Critical Accounting Policies

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

The discounted present value of our proved oil and natural gas reserves is a major component of the ceiling calculation and requires many subjective judgments. Estimates of reserves are forecasts based on engineering and geological analyses. Different reserve engineers may reach different conclusions as to estimated quantities of natural gas or crude oil reserves based on the same information. Our reserve estimates are prepared by independent consultants. The passage of time provides more qualitative information regarding reserve estimates, and revisions are made to prior estimates based on updated information. However, there can be no assurance that significant revisions will not be necessary in the future. Significant downward revisions could result in an impairment representing a non-cash charge to income. There was no impairment for the quarter and nine months ended September 30, 2015 and 2016. In addition to the impact on the calculation of the ceiling test, estimates of proved reserves are also a major component of the calculation of depletion.

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

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

item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Market Risk Related to Oil and Natural Gas Prices

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

Absence of Interest Rate and Currency Exchange Rate Risk

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

item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, our principal executive officer and principal financial officer carried out an evaluation of the effectiveness of our disclosure controls and procedures. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective.

Changes in Internal Controls

There were no changes in our internal controls (as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934) during the quarter ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

The Partnership and the operating partnership are involved in 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.

ITEM 2. ISSUER PURCHASES OF EQUITY SECURITIES

Period	**(a) Total Number of Units Purchased**	**(b) Average Price Paid per Unit**	**(c) Total Number of Units Purchased as Part of Publicly Announced Plans or Programs**	**(d) Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Purchased Under the Plans or Programs**
Month #1 (July 1, 2016 – July 31, 2016)	0	N/A	0	102,149[(1)]
Month #2 (August 1, 2016 – August 31, 2016)	0	N/A	0	102,149[(1)]
Month #3 (September 1, 2016 – September 30, 2016)	16,168[(2)]	15.39	16,168	85,981[(1)]

(1) The number of common units that the operating partnership may grant under the Dorchester Minerals Operating LP Equity Incentive Program, which was approved by our common unitholders on May 20, 2015 (the "**Equity Incentive Program**"), each fiscal year may not exceed 0.333% of the number of common units outstanding at the beginning of the fiscal year. In 2016, the maximum number of common units that could be granted under the Equity Incentive Program is 102,149 common units.

(2) Open-market purchases by Dorchester Minerals Operating LP, an affiliate of the Partnership, pursuant to a Rule 10b5-1 plan adopted on June 16, 2016 for the purpose of satisfying equity awards to be granted pursuant to the Equity Incentive Program.

Item 6. Exhibits

See the attached Index to Exhibits.

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SIGNATURES

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

DORCHESTER MINERALS, L.P.

By: Dorchester Minerals Management LP its General Partner

By: Dorchester Minerals Management GP LLC its General Partner

	By: /s/ William Casey McManemin
	William Casey McManemin
Date: November 3, 2016	Chief Executive Officer

	By: /s/ Leslie Moriyama
	Leslie Moriyama
Date: November 3, 2016	Chief Financial Officer

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INDEX TO EXHIBITS

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

	Certification of Chief Financial Officer of the Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
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)
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

**Furnished herewith

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