DORCHESTER MINERALS LP
Form 10-K
March 06, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2007**

Or

.. **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition Period from ________ to ________**

Commission File Number: 000-50175

DORCHESTER MINERALS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**81-0551518**
(State of incorporation)	**(I.R.S. employer identification number)**

3838 Oak Lawn Avenue, Suite 300

Dallas, Texas 75219

(Address of principal executive offices) (Zip Code)

(214) 559-0300

(Registrant s telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Exchange on which Registered
Common Units Representing Limited Partnership Interests	NASDAQ Global Select Market

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Title of Class

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 5(d) of the Act. Yes ¨ No x

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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 definitions of accelerated filer, large accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Smaller reporting company ¨
(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 ¨ No x

The aggregate market value of the common units held by non-affiliates of the registrant (treating all managers, executive officers and 10% unitholders of the registrant as if they may be affiliates of the registrant) was approximately $388,764,596 as of June 29, 2007, based on $22.00 per unit, the closing price of the common units as reported on the NASDAQ Global Select Market on such date.

Number of Common Units outstanding as of March 6, 2008: 28,240,431

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the registrant s 2008 Annual Meeting of Unitholders to be held on May 13, 2008, are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2007.

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PART I.

ITEM 1. BUSINESS

General

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., Republic Royalty Company, L.P. and Spinnaker Royalty Company, L.P. Dorchester Hugoton was a publicly traded Texas limited partnership, and Republic and Spinnaker were private Texas limited partnerships. Our common units are listed on the NASDAQ Global Select Market. American Stock Transfer & Trust Company is our registrar and transfer agent. Their address and telephone number is 59 Maiden Lane, New York, NY 10038, (800) 937-5449. Our executive offices are located at 3838 Oak Lawn Avenue, Suite 300, Dallas, Texas, 75219-4541, and our telephone number is (214) 559-0300. We have a recently established an Internet website at www.dmlp.net that only contains the last annual meeting presentation and a link to the NASDAQ website. You may obtain all current filings free of charge at the NASDAQ website by clicking Real-Time SEC Filings. We will provide electronic or paper copies of our annual report on Form 10-K, quarterly reports on Form 10-Q, or current reports on Form 8-K and amendments to those reports filed or furnished to the Securities and Exchange Commission (SEC) free of charge upon written request at our executive offices. 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.

Our general partner is Dorchester Minerals Management LP, which is managed by its general partner, Dorchester Minerals Management GP LLC. As a result, the Board of Managers of Dorchester Minerals Management GP LLC exercises effective control of our Partnership. In this report, the term general partner is used as an abbreviated reference to Dorchester Minerals Management LP. Our general partner also controls and owns, directly and indirectly, all of the partnership interests in Dorchester Minerals Operating LP and its general partner, Dorchester Minerals Operating GP LLC. Dorchester Minerals Operating LP owns working interests and other properties underlying our Net Profits Interests, provides day-to-day operational and administrative services to us and our general partner, and is the employer of all the employees who perform such services. In this report, the term operating partnership is used as an abbreviated reference to Dorchester Minerals Operating LP. Our wholly owned subsidiary, Dorchester Minerals Acquisition LP has been and may continue to be used as a vehicle through which we may acquire oil and gas properties.

Our general partner and the operating partnership are Delaware limited partnerships, and the general partner of our general partner and Dorchester Minerals Operating GP LLC are Delaware limited liability companies. These entities and our Partnership were initially formed in December 2001 in connection with the combination that occurred on January 31, 2003. Dorchester Minerals Acquisition LP is an Oklahoma limited partnership, and Dorchester Minerals Acquisition GP, Inc. is an Oklahoma corporation that serves as its general partner. Both were formed in September 2004 in connection with an acquisition of oil and gas properties that was consummated on September 30, 2004.

Our business may be described as the acquisition, ownership and administration of Net Profits Interests and Royalty Properties. The Net Profits Interests represent net profits overriding royalty interests in various properties owned by the operating partnership. The Royalty Properties consist of producing and nonproducing mineral, royalty, overriding royalty, net profits, and leasehold interests located in 573 counties and parishes in 25 states.

Our partnership agreement requires that we distribute quarterly an amount equal to all funds that we receive from the Net Profits Interests and the Royalty Properties less certain expenses and reasonable reserves.

We intend to grow by acquiring additional oil and natural gas properties, subject to the limitations described below. The approval of the holders of a majority of our outstanding common units is required for our general partner to cause us to acquire or obtain any oil and natural gas property interest, unless the acquisition is complementary to our business and is made either:

- in exchange for our limited partner interests, including common units, not exceeding 20% of the common units outstanding after issuance; or
- in exchange for cash, if the aggregate cost of any acquisitions made for cash during the twelve-month period ending on the first to occur of the execution of a definitive agreement for the acquisition or its consummation is no more than 10% of our aggregate cash distributions for the four most recent fiscal quarters.

Unless otherwise approved by the holders of a majority of our common units, in the event that we acquire properties for a combination of cash and limited partner interests, including common units, (i) the cash component of the acquisition consideration must be equal to or less than 5% of the aggregate cash distributions made by our Partnership for the four most recent quarters and (ii) the amount of limited partnership interests, including common units, to be issued in such acquisition, after giving effect to such issuance, shall not exceed 10% of the common units outstanding.

Credit Facilities and Financing Plans

We do not have a credit facility in place, nor do we anticipate doing so. We do not anticipate incurring any debt, other than trade debt incurred in the ordinary course of our business. Our partnership agreement prohibits us from incurring 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), in order to avoid unrelated business taxable income for federal income tax purposes. We may finance any growth of our business through acquisitions of oil and natural gas properties by issuing additional limited partnership interests or with cash, subject to the limits described above and in our partnership agreement.

Under our partnership agreement, we may also finance our growth through the issuance of additional partnership securities, including options, rights, warrants and appreciation rights with respect to partnership securities from time to time in exchange for the consideration and on the terms and conditions established by our general partner in its sole discretion. However, we may not issue limited partnership interests that would represent over 20% of the outstanding limited partnership interests immediately after giving effect to such issuance or that would have greater rights or powers than our common units without the approval of the holders of a majority of our outstanding common units. Except in connection with qualifying acquisitions, we do not currently anticipate issuing additional partnership securities. On May 2, 2005, we filed a registration statement on Form S-4 with the Securities and Exchange Commission to register 5,000,000 common units that may be offered and issued by the Partnership from time to time in connection with asset acquisitions or other business combination transactions. At present, none of the 5,000,000 units have been offered.

Regulation

Many aspects of the production, pricing and marketing of crude oil and natural gas are regulated by federal and state agencies. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, which frequently increases the regulatory burden on affected members of the industry.

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes:

- permits for the drilling of wells;
- bonding requirements in order to drill or operate wells;
- the location and number of wells;

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- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandonment of wells;
- numerous federal and state safety requirements;
- environmental requirements;
- property taxes and severance taxes; and
- specific state and federal income tax provisions.

Oil and natural gas operations are also subject to various conservation laws and regulations. These regulations govern the size of drilling and spacing units or proration units and the density of wells that may be drilled and the unitization or pooling of oil and natural gas properties. In addition, state conservation laws establish a maximum allowable production from oil and natural gas wells. These state laws also generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. These regulations can limit the amount of oil and natural gas that the operators of our properties can produce.

The transportation of natural gas after sale by operators of our properties is sometimes subject to regulation by state authorities. The interstate transportation of natural gas is subject to federal governmental regulation, including regulation of tariffs and various other matters, by the Federal Energy Regulatory Commission.

Customers and Pricing

The pricing of oil and natural gas sales is primarily determined by supply and demand in the marketplace and can fluctuate considerably. As a royalty owner and non-operator, we have extremely limited access to timely information, involvement, and operational control over the volumes of oil and natural gas produced and sold and the terms and conditions on which such volumes are marketed and sold.

Since 2004 the operating partnership has sold most of its natural gas production to Williams Power Company, Inc. on a daily market price basis using a yearly contract that will continue through October 2008. The operating partnership frequently reviews alternative gas purchasers. We believe that the loss of Williams Power by the operating partnership or the loss of any single customer would not have a material adverse effect on us due to alternative purchasers.

Competition

The energy industry in which we compete is subject to intense competition among many companies, both larger and smaller than we are, many of which have financial and other resources greater than we have.

Operating Hazards and Uninsured Risks

Our operations do not directly involve the operational risks and uncertainties associated with drilling for, and the production and transportation of, oil and natural gas. However, we may be indirectly affected by the operational risks and uncertainties faced by the operators of our properties, including the operating partnership, whose operations may be materially curtailed, delayed or canceled as a result of numerous factors, including:

the presence of unanticipated pressure or irregularities in formations;

accidents;

title problems;

weather conditions;

- compliance with governmental requirements; and
- shortages or delays in the delivery of equipment.

Also, the ability of the operators of our properties to market oil and natural gas production depends on numerous factors, many of which are beyond their control, including:

- capacity and availability of oil and natural gas systems and pipelines;
- effect of federal and state production and transportation regulations;
- changes in supply and demand for oil and natural gas; and
- creditworthiness of the purchasers of oil and natural gas.

The occurrence of an operational risk or uncertainty that materially impacts the operations of the operators of our properties could have a material adverse effect on the amount that we receive in connection with our interests in production from our properties, which could have a material adverse effect on our financial condition or result of operations.

In accordance with customary industry practices, we maintain insurance against some, but not all, of the risks to which our business exposes us. While we believe that we are reasonably insured against these risks, the occurrence of an uninsured loss could have a material adverse effect on our financial condition or results of operations.

Employees

As of February 28, 2008, the operating partnership had 18 full-time employees in our Dallas, Texas office and nine full-time employees in field locations.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

Our cash distributions are highly dependent on oil and natural gas prices, which have historically been very volatile.

Our quarterly cash distributions depend significantly on the prices realized from the sale of oil and, in particular, natural gas. Historically, the markets for oil and natural gas have been volatile and may continue to be volatile in the future. Various factors that are beyond our control will affect prices of oil and natural gas, such as:

- the worldwide and domestic supplies of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries and others to agree to and maintain oil prices and production controls;

political instability or armed conflict in oil-producing regions;

the price and level of foreign imports;

the level of consumer demand;

the price and availability of alternative fuels;

the availability of pipeline capacity;

weather conditions;

domestic and foreign governmental regulations and taxes; and

the overall economic environment.

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Lower oil and natural gas prices may reduce the amount of oil and natural gas that is economic to produce and may reduce our revenues and operating income. The volatility of oil and natural gas prices reduces the accuracy of estimates of future cash distributions to unitholders.

Terrorist attacks on oil and natural gas production facilities, transportation systems and storage facilities could have a material adverse impact on our business.

Oil and natural gas production facilities, transportation systems and storage facilities could be targets of terrorist attacks. These attacks could have a material adverse impact if certain oil and natural gas infrastructure integral to our operations were interrupted, damaged or destroyed, thus preventing the sale of oil and natural gas.

We do not control operations and development of the Royalty Properties or the properties underlying the Net Profits Interests that the operating partnership does not operate, which could impact the amount of our cash distributions.

As the owner of a fractional undivided mineral or royalty interest, we do not control the development of the Royalty or Net Profits Interests properties or the volumes of oil and natural gas produced from them, and our ability to influence development of nonproducing properties is severely limited. Also, since one of our stated business objectives is to avoid the generation of unrelated business taxable income, we are prohibited from participation in the development of our properties as a working interest or other expense-bearing owner. The decision to explore or develop these properties, including infill drilling, exploration of horizons deeper or shallower than the currently producing intervals, and application of enhanced recovery techniques will be made by the operator and other working interest owners of each property (including our lessees) and may be influenced by factors beyond our control, including but not limited to oil and natural gas prices, interest rates, budgetary considerations and general industry and economic conditions.

Our unitholders are not able to influence or control the operation or future development of the properties underlying the Net Profits Interests. The operating partnership is unable to influence significantly the operations or future development of properties that it does not operate. The operating partnership and the other current operators of the properties underlying the Net Profits Interests are under no obligation to continue operating the underlying properties. The operating partnership can sell any of the properties underlying the Net Profits Interests that it operates and relinquish the ability to control or influence operations. Any such sale or transfer must also simultaneously include the Net Profits Interests at a corresponding price. Our unitholders do not have the right to replace an operator.

Our lease bonus revenue depends in significant part on the actions of third parties, which are outside of our control.

A significant portion of the Royalty Properties are unleased mineral interests. With limited exceptions, we have the right to grant leases of these interests to third parties. We anticipate receiving cash payments as bonus consideration for granting these leases in most instances. Our ability to influence third parties decisions to become our lessees with respect to these nonproducing properties is severely limited, and those decisions may be influenced by factors beyond our control, including but not limited to oil and natural gas prices, interest rates, budgetary considerations and general industry and economic conditions.

The operating partnership may transfer or abandon properties that are subject to the Net Profits Interests.

Our general partner, through the operating partnership, may at any time transfer all or part of the properties underlying the Net Profits Interests. Our unitholders are not entitled to vote on any transfer; however, any such transfer must also simultaneously include the Net Profits Interests at a corresponding price.

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The operating partnership or any transferee may abandon any well or property if it reasonably believes that the well or property can no longer produce in commercially economic quantities. This could result in termination of the Net Profits Interests relating to the abandoned well.

Cash distributions are affected by production and other costs, some of which are outside of our control.

The cash available for distribution that comes from our royalty and mineral interests, including the Net Profits Interests, is directly affected by increases in production costs and other costs. Some of these costs are outside of our control, including costs of regulatory compliance and severance and other similar taxes. Other expenditures are dictated by business necessity, such as drilling additional wells in response to the drilling activity of others.

Our oil and natural gas reserves and the underlying properties are depleting assets, and there are limitations on our ability to replace them.

Our revenues and distributions depend in large part on the quantity of oil and natural gas produced from properties in which we hold an interest. Over time, all of our producing oil and natural gas properties will experience declines in production due to depletion of their oil and natural gas reservoirs, with the rates of decline varying by property. Replacement of reserves to maintain production levels requires maintenance, development or exploration projects on existing properties, or the acquisition of additional properties.

The timing and size of any maintenance, development or exploration projects will depend on the market prices of oil and natural gas and on other factors beyond our control. Many of the decisions regarding implementation of such projects, including drilling or exploration on any unleased and undeveloped acreage, will be made by third parties. In addition, development possibilities in the Hugoton field are limited by the developed nature of that field and by regulatory restrictions.

Our ability to increase reserves through future acquisitions is limited by restrictions on our use of cash and limited partnership interests for acquisitions and by our general partner s obligation to use all reasonable efforts to avoid unrelated business taxable income. In addition, the ability of affiliates of our general partner to pursue business opportunities for their own accounts without tendering them to us in certain circumstances may reduce the acquisitions presented to our Partnership for consideration.

Drilling activities on our properties may not be productive, which could have an adverse effect on future results of operations and financial condition.

The operating partnership may undertake drilling activities in limited circumstances on the properties underlying the Net Profits Interests, and third parties may undertake drilling activities on our other properties. Any increases in our reserves will come from such drilling activities or from acquisitions.

Drilling involves a wide variety of risks, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be delayed or canceled as a result of a variety of factors, including:

- pressure or irregularities in formations;
- equipment failures or accidents;
- unexpected drilling conditions;
- shortages or delays in the delivery of equipment;
- adverse weather conditions; and

disputes with drill-site owners.

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Future drilling activities on our properties may not be successful. If these activities are unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. In addition, under the terms of the Net Profits Interests, the costs of unsuccessful future drilling on the working interest properties that are subject to the Net Profits Interests will reduce amounts payable to us under the Net Profits Interests by 96.97% of these costs.

Our ability to identify and capitalize on acquisitions is limited by contractual provisions and substantial competition.

Our partnership agreement limits our ability to acquire oil and natural gas properties in the future, especially for consideration other than our limited partnership interests. Because of the limitations on our use of cash for acquisitions and on our ability to accumulate cash for acquisition purposes, we may be required to attempt to effect acquisitions with our limited partnership interests. However, sellers of properties we would like to acquire may be unwilling to take our limited partnership interests in exchange for properties.

Our partnership agreement obligates our general partner to use all reasonable efforts to avoid generating unrelated business taxable income. Accordingly, to acquire working interests we would have to arrange for them to be converted into overriding royalty interests, net profits interests, or another type of interest that does not generate unrelated business taxable income. Third parties may be less likely to deal with us than with a purchaser to which such a condition would not apply. These restrictions could prevent us from pursuing or completing business opportunities that might benefit us and our unitholders, particularly unitholders who are not tax-exempt investors.

The duty of affiliates of our general partner to present acquisition opportunities to our Partnership is limited, pursuant to the terms of the Amended and Restated Business Opportunities Agreement. Accordingly, business opportunities that could potentially be pursued by us might not necessarily come to our attention, which could limit our ability to pursue a business strategy of acquiring oil and natural gas properties.

We compete with other companies and producers for acquisitions of oil and natural gas interests. Many of these competitors have substantially greater financial and other resources than we do.

Any future acquisitions will involve risks that could adversely affect our business, which our unitholders generally will not have the opportunity to evaluate.

Our current strategy contemplates that we may grow through acquisitions. We expect to participate in discussions relating to potential acquisition and investment opportunities. If we consummate any additional acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in connection with the acquisition, unless the terms of the acquisition require approval of our unitholders. Additionally, our unitholders will bear 100% of the dilution from issuing new common units while receiving essentially 96% of the benefit as 4% of the benefit goes to our general partner.

Acquisitions and business expansions involve numerous risks, including assimilation difficulties, unfamiliarity with new assets or new geographic areas and the diversion of management s attention from other business concerns. In addition, the success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attributable to reserves and to assess possible environmental liabilities. Our review and analysis of properties prior to any acquisition will be subject to uncertainties and, consistent with industry practice, may be limited in scope. We may not be able to successfully integrate any oil and natural gas properties that we acquire into our operations, or we may not achieve desired profitability objectives.

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A natural disaster or catastrophe could damage pipelines, gathering systems and other facilities that service our properties, which could substantially limit our operations and adversely affect our cash flow.

If gathering systems, pipelines or other facilities that serve our properties are damaged by any natural disaster, accident, catastrophe or other event, our income could be significantly interrupted. Any event that interrupts the production, gathering or transportation of our oil and natural gas, or which causes us to share in significant expenditures not covered by insurance, could adversely impact the market price of our limited partnership units and the amount of cash available for distribution to our unitholders. We do not carry business interruption insurance.

The vast majority of the properties subject to the Net Profits Interests are geographically concentrated, which could cause net proceeds payable under the Net Profits Interests to be impacted by regional events.

The vast majority of the properties subject to the Net Profits Interests are all natural gas properties that are located almost exclusively in the Hugoton field in Oklahoma and Kansas. Because of this geographic concentration, any regional events, including natural disasters that increase costs, reduce availability of equipment or supplies, reduce demand or limit production may impact the net proceeds payable under the Net Profits Interests more than if the properties were more geographically diversified.

The number of prospective natural gas purchasers and methods of delivery are considerably less than would otherwise exist from a more geographically diverse group of properties. As a result, natural gas sales after gathering and compression tend to be sold to one buyer in each state, thereby increasing credit risk.

Under the terms of the Net Profits Interests, much of the economic risk of the underlying properties is passed along to us.

Under the terms of the Net Profits Interests, virtually all costs that may be incurred in connection with the properties, including overhead costs that are not subject to an annual reimbursement limit, are deducted as production costs or excess production costs in determining amounts payable to us. Therefore, to the extent of the revenues from the burdened properties, we bear 96.97% of the costs of the working interest properties. If costs exceed revenues, we do not receive any payments under the Net Profits Interests. However, except as described below, we are not required to pay any excess costs.

The terms of the Net Profits Interests provide for excess costs that cannot be charged currently because they exceed current revenues to be accumulated and charged in future periods, which could result in our not receiving any payments under the Net Profits Interests until all prior uncharged costs have been recovered by the operating partnership.

Damage claims associated with the production and gathering of our oil and natural gas properties could affect our cash flow.

The operating partnership owns and operates gathering systems and compression facilities. Casualty losses or damage claims from these operations would be production costs under the terms of the Net Profits Interests and could adversely affect our cash flow.

We may indirectly experience costs from repair or replacement of aging equipment.

Some of the operating partnership s current working interest wells were drilled and have been producing since prior to 1954. The 132-mile Oklahoma gas pipeline gathering system was originally installed in or about 1948 and because of its age is in need of periodic repairs and upgrades. Should major components of this system require significant repairs or replacement, the operating partnership may incur substantial capital expenditures in the operation of the Oklahoma properties, which, as production costs, would reduce our cash flow from these properties.

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Our cash flow is subject to operating hazards and unforeseen interruptions for which we may not be fully insured.

Neither we nor the operating partnership are fully insured against certain risks, either because such insurance is not available or because of high premium costs. Operations that affect the properties are subject to all of the risks normally incident to the oil and natural gas business, including blowouts, cratering, explosions and pollution and other environmental damage, any of which could result in substantial decreases in the cash flow from our overriding royalty interests and other interests due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Any uninsured costs relating to the properties underlying the Net Profits Interests will be deducted as a production cost in calculating the net proceeds payable to us.

Governmental policies, laws and regulations could have an adverse impact on our business and cash distributions.

Our business and the properties in which we hold interests are subject to federal, state and local laws and regulations relating to the oil and natural gas industry as well as regulations relating to safety matters. These laws and regulations can have a significant impact on production and costs of production. For example, both Oklahoma and Kansas, where properties that are subject to the Net Profits Interests are located, have the ability, directly or indirectly, to limit production from those properties, and such limitations or changes in those limitations could negatively impact us in the future.

As another example, Oklahoma regulations currently require administrative hearings to change the concentration of the operating partnership s gas production wells from one well for each 640 acres in the Guymon-Hugoton field. Previously, certain interested parties have sought regulatory changes in Oklahoma for infill, or increased density, drilling similar to that which is available in Kansas, which allows one well for each 320 acres. Should Oklahoma change its existing regulations to readily permit infill drilling, it is possible that a number of producers will commence increased density drilling in areas adjacent to the properties in Oklahoma that are subject to the Net Profits Interests. If the operating partnership or other operators of our properties do not do the same, our production levels relating to these properties may decrease, or mineral owners may demand increased density drilling. Capital expenditures relating to increased density on the properties underlying the Net Profits Interests would be deducted from amounts payable to us under the Net Profits Interests.

Environmental costs and liabilities and changing environmental regulation could affect our cash flow.

As with other companies engaged in the ownership and production of oil and natural gas, we always expect to have some risk of exposure to environmental costs and liabilities because the costs associated with environmental compliance or remediation could reduce the amount we would receive from our properties. The properties in which we hold interests are subject to extensive federal, state, tribal and local regulatory requirements relating to environmental affairs, health and safety and waste management. Governmental authorities have the power to enforce compliance with applicable regulations and permits, which could increase production costs on our properties and affect their cash flow. Third parties may also have the right to pursue legal actions to enforce compliance. It is likely that expenditures in connection with environmental matters, individually or as part of normal capital expenditure programs, will affect the net cash flow from our properties. Future environmental law developments, such as stricter laws, regulations or enforcement policies, could significantly increase the costs of production from our properties and reduce our cash flow.

Our oil and gas reserve data and future net revenue estimates are uncertain.

Estimates of proved reserves and related future net revenues are projections based on engineering data and reports of independent consulting petroleum engineers hired for that purpose. The process of estimating reserves requires substantial judgment, resulting in imprecise determinations. Different reserve engineers may make different estimates of reserve quantities and related revenue based on the same data. Therefore, those estimates should not be construed as being accurate estimates of the current market value of our proved reserves. If these estimates prove to be inaccurate, our business may be adversely affected by lower revenues. We are affected by changes in oil and natural gas prices. Oil prices and natural gas prices may experience inverse price changes.

Risks Inherent In An Investment In Our Common Units

Cost reimbursement due our general partner may be substantial and reduce our cash available to distribute to our unitholders.

Prior to making any distribution on the common units, we reimburse the general partner and its affiliates for reasonable costs and expenses of management. The reimbursement of expenses could adversely affect our ability to pay cash distributions to our unitholders. Our general partner has sole discretion to determine the amount of these expenses, subject to the annual limit of 5% of an amount primarily based on our distributions to partners for that fiscal year. The annual limit includes carry-forward and carry-back features, which could allow costs in a year to exceed what would otherwise be the annual reimbursement limit. In addition, our general partner and its affiliates may provide us with other services for which we will be charged fees as determined by our general partner.

Our net income as reported for tax and financial statement purposes may differ significantly from our cash flow that is used to determine cash available for distributions.

Net income as reported for financial statement purposes is presented on an accrual basis in conformity with accounting principles generally accepted in the United States of America. Unitholder K-1 tax statements are calculated based on applicable tax conventions, and taxable income as calculated for each year will be allocated among unitholders who hold units on the last day of each month. Distributions, however, are calculated on the basis of actual cash receipts, changes in cash reserves, and disbursements during the relevant reporting period. Consequently, due to timing differences between the receipt of proceeds of production and the point in time at which the production giving rise to those proceeds actually occurs, net income reported on our consolidated financial statements and on unitholder K-1 s will not reflect actual cash distributions during that reporting period.

Our unitholders have limited voting rights and do not control our general partner, and their ability to remove our general partner is limited.

Our unitholders have only limited voting rights on matters affecting our business. The general partner of our general partner manages our activities. Our unitholders only have the right to annually elect the managers comprising the Advisory Committee of the Board of Managers of the general partner of our general partner. Our unitholders do not have the right to elect the other managers of the general partner of our general partner on an annual or any other basis.

Our general partner may not be removed as our general partner except upon approval by the affirmative vote of the holders of at least a majority of our outstanding common units (including common units owned by our general partner and its affiliates), subject to the satisfaction of certain conditions. Our general partner and its affiliates do not own sufficient common units to be able to prevent its removal as general partner, but they do own sufficient common units to make the removal of our general partner by other unitholders difficult.

These provisions may discourage a person or group from attempting to remove our general partner or acquire control of us without the consent of our general partner. As a result of these provisions, the price at which our common units trade may be lower because of the absence or reduction of a takeover premium in the trading price.

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The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner has agreed not to withdraw voluntarily as our general partner on or before December 31, 2010 (with limited exceptions), unless the holders of at least a majority of our outstanding common units (excluding common units owned by our general partner and its affiliates) approve the withdrawal. However, the general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Other than some transfer restrictions agreed to among the owners of our general partner relating to their interests in our general partner, there is no restriction in our partnership agreement or otherwise for the benefit of our limited partners on the ability of the owners of our general partner to transfer their ownership interests to a third party. The new owner of the general partner would then be in a position to replace the management of our Partnership with its own choices.

Our general partner and its affiliates have conflicts of interests, which may permit our general partner and its affiliates to favor their own interests to the detriment of unitholders.

We and our general partner and its affiliates share, and therefore compete for, the time and effort of general partner personnel who provide services to us. Officers of our general partner and its affiliates do not, and are not required to, spend any specified percentage or amount of time on our business. In fact, our general partner has a duty to manage our Partnership in the best interests of our unitholders, but it also has a duty to operate its business for the benefit of its partners. Some of our officers are also involved in management and ownership roles in other oil and natural gas enterprises and have similar duties to them and devote time to their businesses. Because these shared officers function as both our representatives and those of our general partner and its affiliates and of third parties, conflicts of interest could arise between our general partner and its affiliates, on the one hand, and us or our unitholders, on the other, or between us or our unitholders on the one hand and the third parties for which our officers also serve management functions. As a result of these conflicts, our general partner and its affiliates may favor their own interests over the interests of unitholders.

We may issue additional securities, diluting our unitholders interests.

We can and may issue additional common units and other capital securities representing limited partnership units, including options, warrants, rights, appreciation rights and securities with rights to distributions and allocations or in liquidation equal or superior to the securities described in this document; however, a majority of the unitholders must approve such issuance if (i) the partnership securities to be issued will have greater rights or powers than our common units or (ii) if after giving effect to such issuance, such newly issued partnership securities represent over 20% of the outstanding limited partnership interests.

If we issue additional common units, it will reduce our unitholders proportionate ownership interest in us. This could cause the market price of the common units to fall and reduce the per unit cash distributions paid to our unitholders. In addition, if we issued limited partnership units with voting rights superior to the common units, it could adversely affect our unitholders voting power.

Our unitholders may not have limited liability in the circumstances described below and may be liable for the return of certain distributions.

Under Delaware law, our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business.

The general partner generally has unlimited liability for the obligations of our Partnership, such as its debts and environmental liabilities, except for those contractual obligations of our Partnership that are expressly made without recourse to the general partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under certain circumstances, a unitholder may be liable for the amount of distribution for a period of three years from the date of distribution.

Because we conduct our business in various states, the laws of those states may pose similar risks to our unitholders. To the extent to which we conduct business in any state, our unitholders might be held liable for our obligations as if they were general partners if a court or government agency determined that we had not complied with that state s partnership statute, or if rights of unitholders constituted participation in the control of our business under that state s partnership statute. In some of the states in which we conduct business, the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established.

We are dependent upon key personnel, and the loss of services of any of our key personnel could adversely affect our operations.

Our continued success depends to a considerable extent upon the abilities and efforts of the senior management of our general partner, particularly William Casey McManemin, its Chief Executive Officer, James E. Raley, its Chief Operating Officer, and H. C. Allen, Jr., its Chief Financial Officer. The loss of the services of any of these key personnel could have a material adverse effect on our results of operations. We have not obtained insurance or entered into employment agreements with any of these key personnel.

We are dependent on service providers who assist us with providing Schedule K-1 tax statements to our unitholders.

There are a very limited number of service firms that currently perform the detailed computations needed to provide each unitholder with estimated depletion and other tax information to assist the unitholder in various United States income tax computations. There are also very few publicly traded limited partnerships that need these services. As a result, the future costs and timeliness of providing Schedule K-1 tax statements to our unitholders is uncertain.

Tax Risks

We have not received a ruling or assurances from the IRS or any state or local taxing authority on any matters affecting us.

We have not requested, and will not request, any ruling from the Internal Revenue Service, or IRS, or any state or local taxing authority with respect to owning and disposing of our common units or any other matter. It may be necessary to resort to administrative or court proceedings in an effort to sustain some or all of those conclusions or positions taken or expressed by us, and some or all of those conclusions or positions ultimately may not be sustained. Our unitholders and general partner will bear, directly or indirectly, the costs of any contest with the IRS or other taxing authority.

We will be subject to federal income tax if we are classified as a corporation and not as a partnership for federal income tax purposes.

As stated above, we have not requested, and will not request, any ruling from the IRS as to our status as a partnership for federal income tax purposes. If the IRS were to challenge our federal income tax status, such a challenge could result in an audit of our unitholders tax returns and adjustments to items on their tax returns that are unrelated to their ownership of our common units. In addition, our unitholders would bear the cost of any expenses incurred in connection with an examination of their personal tax returns.

If we were taxable as a corporation for federal income tax purposes in any taxable year, our income, gains, losses and deductions would be reflected on our tax return rather than being passed through proportionately to our unitholders, and our net income would be taxed at corporate rates. In addition, some or all of the distributions made to our unitholders would be treated as dividend income without offset for depletion, and distributions would be reduced as a result of the federal, state and local taxes paid by us.

The IRS could reallocate items of income, gain, deduction and loss between transferors and transferees of common units if the IRS does not accept our monthly convention for allocating such items.

In general, each of our items of income, gain, loss and deduction will, for federal income tax purposes, be determined annually, and one twelfth of each annual amount will be allocated to those unitholders who hold common units on the last business day of each month in that year. In certain circumstances we may make these allocations in connection with extraordinary or nonrecurring events on a more frequent basis. As a result, transferees of our common units may be allocated items of our income, gain, loss and deduction realized by us prior to the date of their acquisition of our common units. There is no specific authority addressing the utilization of this method of allocating items of income, gain, loss and deduction by a publicly traded partnership such as us between transferors and transferees of its common units. If this method is determined to be an unreasonable method of allocation, our income, gain, loss and deduction would be reallocated among our unitholders and our general partner, and our unitholders may have more taxable income or less taxable loss. Our general partner is authorized to revise our method of allocation between transferors and transferees, as well as among our other unitholders whose common units otherwise vary during a taxable period, to conform to a method permitted or required by the Internal Revenue Code and the regulations or rulings promulgated thereunder.

Our unitholders may not be able to deduct losses attributable to their common units.

Any losses relating to our unitholders common units will be losses related to portfolio income and their ability to use such losses may be limited.

Our unitholders partnership tax information may be audited.

We will furnish our unitholders with a Schedule K-1 tax statement that sets forth their allocable share of income, gains, losses and deductions. In preparing this schedule, we will use various accounting and reporting conventions and various depreciation and amortization methods we have adopted. This schedule may not yield a result that conforms to statutory or regulatory requirements or to administrative pronouncements of the IRS. Further, our tax return may be audited, and any such audit could result in an audit of our unitholders individual income tax returns as well as increased liabilities for taxes because of adjustments resulting from the audit. An audit of our unitholders returns also could be triggered if the tax information relating to their common units is not consistent with the Schedule K-1 that we are required to provide to the IRS.

Our unitholders may have more taxable income or less taxable loss with respect to their common units if the IRS does not respect our method for determining the adjusted tax basis of their common units.

We have adopted a reporting convention that will enable our unitholders to track the basis of their individual common units or unit groups and use this basis in calculating their basis adjustments under Section 743 of the Internal Revenue Code and gain or loss on the sale of common units. This method does not comply with an IRS ruling that requires a portion of the combined tax basis of all common units to be allocated to each of the common units owned by a unitholder upon a sale or disposition of less than all of the common units and may be challenged by the IRS. If such a challenge is successful, our unitholders may have to recognize more taxable income or less taxable loss with respect to common units disposed of and common units they continue to hold.

Tax-exempt investors may recognize unrelated business taxable income.

Generally, unrelated business taxable income, or UBTI, can arise from a trade or business unrelated to the exempt purposes of the tax-exempt entity that is regularly carried on by either the tax-exempt entity or a

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partnership in which the tax-exempt entity is a partner. However, UBTI does not apply to interest income, royalties (including overriding royalties) or net profits interests, whether the royalties or net profits are measured by production or by gross or taxable income from the property. Pursuant to the provisions of our partnership agreement, our general partner shall use all reasonable efforts to prevent us from realizing income that would constitute UBTI. In addition, our general partner is prohibited from incurring certain types and amounts of indebtedness and from directly owning working interests or cost bearing interests and, in the event that any of our assets become working interests or cost bearing interests, is required to assign such interests to the operating partnership subject to the reservation of a net profits overriding royalty interest. However, it is possible that we may realize income that would constitute UBTI in an effort to maximize unitholder value.

Tax consequences of certain Net Profits Interests are uncertain.

We are prohibited from owning working interests or cost-bearing interests. At the time of the creation of the Minerals NPI, we assigned to the operating partnership all rights in any such working interests or cost-bearing interests that might subsequently be created from the mineral properties that were and are subject of the Minerals NPI. As additional working interests and other cost-bearing interests are created out of such mineral properties, they are owned by the operating partnership pursuant to such original assignment, and we have executed various documents since the creation of the Minerals NPI to confirm such treatment under the original assignment. This treatment could be characterized differently by the IRS, and in such a case we are unable to predict, with certainty, all of the income tax consequences relating to the Minerals NPI as it relates to such working interests and other cost-bearing interests.

Our unitholders may not be entitled to deductions for percentage depletion with respect to our oil and natural gas interests.

Our unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to the oil and natural gas interests owned by us. However, percentage depletion is generally available to a unitholder only if he qualifies under the independent producer exemption contained in the Internal Revenue Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas, or derivative products or the operation of a major refinery. If a unitholder does not qualify under the independent producer exemption, he generally will be restricted to deductions based on cost depletion.

Our unitholders may have more taxable income or less taxable loss on an ongoing basis if the IRS does not accept our method of allocating depletion deductions.

The Internal Revenue Code requires that income, gain, loss and deduction attributable to appreciated or depreciated property that is contributed to a partnership in exchange for a partnership interest in the partnership must be allocated so that the contributing partner is charged with, or benefits from, gain or unrealized loss, referred to as Built-in Gain and Built-in Loss, respectively, associated with the property at the time of its contribution to the partnership. Our partnership agreement provides that the adjusted tax basis of the oil and natural gas properties contributed to us is allocated to the contributing partners for the purpose of separately determining depletion deductions. Any gain or loss resulting from the sale of property contributed to us will be allocated to the partners that contributed the property, in proportion to their percentage interest in the contributed property, to take into account any Built-in Gain or Built-in Loss. This method of allocating Built-in Gain and Built-in Loss is not specifically permitted by United States Treasury regulations, and the IRS may challenge this method. Such a challenge, if successful, could cause our unitholders to recognize more taxable income or less taxable loss on an ongoing basis in respect of their common units.

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Our unitholders may have more taxable income or less taxable loss on an ongoing basis if the IRS does not accept our method of determining a unitholder s share of the basis of partnership property.

Our general partner utilizes a method of calculating each unitholder s share of the basis of partnership property that results in an aggregate basis for depletion purposes that reflects the purchase price of common units as paid by the unitholder. This method is not specifically authorized under applicable Treasury regulations, and the IRS may challenge this method. Such a challenge, if successful, could cause our unitholders to recognize more taxable income or less taxable loss on an ongoing basis in respect of their common units.

The ratio of the amount of taxable income that will be allocated to a unitholder to the amount of cash that will be distributed to a unitholder is uncertain, and cash distributed to a unitholder may not be sufficient to pay tax on the income we allocate to a unitholder.

The amount of taxable income realized by a unitholder will be dependent upon a number of factors including: (i) the amount of taxable income recognized by us; (ii) the amount of any gain recognized by us that is attributable to specific asset sales that may be wholly or partially attributable to Built-in Gain and the resulting allocation of such gain to a unitholder, depending on the asset being sold; (iii) the amount of basis adjustment pursuant to the Internal Revenue Code available to a unitholder based on the purchase price for any common units and the amount by which such price was greater or less than a unitholder s proportionate share of inside tax basis of our assets attributable to the common units when the common units were purchased; and (iv) the method of depletion available to a unitholder. Therefore, it is not possible for us to predict the ratio of the amount of taxable income that will be allocated to a unitholder to the amount of cash that will be distributed to a unitholder.

A unitholder may lose his status as a partner of our Partnership for federal income tax purposes if he lends our common units to a short seller to cover a short sale of such common units.

If a unitholder loans his common units to a short seller to cover a short sale of common units, he may be considered as having disposed of his ownership of those common units for federal income tax purposes. If so, the unitholder would no longer be a partner of our Partnership for tax purposes with respect to those common units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period, any of our income, gain, loss or deduction with respect to those common units would not be reportable, and any cash distributions received for those common units would be fully taxable and may be treated as ordinary income.

If we are not notified (either directly or through a broker) of a sale or other transfer of common units, some distributions and federal income tax information or reports with respect to such units may not be provided to the purchaser or other transferee of the units and may instead continue to be provided to the original transferor.

If our transfer agent or any other nominee holding common units on behalf of a partner is not timely notified, and a proper transfer of ownership is not recorded on the appropriate books and records, of a sale or other transfer of common units, some distributions and federal income tax information or reports with respect to these common units may not be made or provided to the transferee of the units and may instead continue to be made or provided to the original transferor. Notwithstanding a transferee s failure to receive distributions and federal income tax information or reports from us with respect to these units, the IRS may contend that such transferee is a partner for federal income tax purposes and that some allocations of income, gain, loss or deduction by us should have been reported by such transferee. Alternatively, the IRS may contend that the transferor continues to be a partner for federal income tax purposes and that allocations of income, gain, loss or deduction by us should have been reported by such transferor. If the transferor is not treated as a partner for federal income tax purposes, any cash distributions received by such transferor with respect to the transferred units following the transfer would be fully taxable as ordinary income to the transferor.

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A sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period could result in adverse tax consequences to a unitholder.

We will terminate for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. A termination would result in the closing of our taxable year for a unitholder. As a result, if a unitholder has a different taxable year than we have, he may be required to include his allocable share of our income, gain, loss, deduction, credits and other items from both the taxable year ending prior to the year of our termination and the short taxable year ending at the time of our termination in the same taxable year. A termination also could result in penalties if we were unable to determine that the termination occurred.

Foreign, state and local taxes could be withheld on amounts otherwise distributable to a unitholder.

A unitholder may be required to file tax returns and be subject to tax liability in the foreign, state or local jurisdictions where he resides and in each state or local jurisdiction in which we have assets or otherwise do business. We also may be required to withhold state income tax from distributions otherwise payable to a unitholder, and state income tax may be withheld by others on royalty payments to us.

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 sin words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other forward-looking information.

These forward-looking statements are made 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, including those discussed under Risk Factors and elsewhere in this report.

You should read these statements carefully because they may 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 Risk Factors and elsewhere 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Facilities

Our office in Dallas consists of 11,847 square feet of leased office space. The operating partnership owns a field office in Hooker, Oklahoma and leases part of an office in Amarillo, Texas.

Properties

We own two categories of properties: the Royalty Properties and the Net Profits Interests.

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Royalty Properties

We own Royalty Properties representing producing and nonproducing mineral, royalty, overriding royalty, net profits and leasehold interests in properties located in 573 counties and parishes in 25 states. Acreage amounts listed herein represent our best estimates based on information provided to us as a royalty owner. Due to the significant number of individual deeds, leases and similar instruments involved in the acquisition and development of the Royalty Properties by us or our predecessors, acreage amounts are subject to change as new information becomes available. In addition, as a royalty owner, our access to information concerning activity and operations on the Royalty Properties is limited. Most of our producing properties are subject to old leases and other contracts pursuant to which we are not entitled to well information. Some of our newer leases provide for access to technical data and other information. We may have limited access to public data in some areas through third party subscription services. Consequently, the exact number of wells producing from or drilling on the Royalty Properties is not determinable. The primary manner by which we will become aware of activity on the Royalty Properties is the receipt of division orders or other correspondence from operators or purchasers.

Acreage Summary

The following table sets forth as of December 31, 2007, a summary of our gross and net, where applicable, acres of mineral, royalty, overriding royalty and leasehold interests, and a compilation of the number of counties and parishes and states in which these interests are located. The majority of our net mineral acres are unleased. Acreage amounts may not add across due to overlapping ownership among categories.

	Mineral	Royalty	Overriding Royalty	Leasehold	Total
Number of States	25	17	18	8	25
Number of Counties/Parishes	464	190	140	35	573
Gross	2,258,165	586,418	243,038	35,398	3,122,979
Net (where applicable)	344,822				344,822

Our net interest in production from royalty, overriding royalty and leasehold interests is based on lease royalty and other third-party contractual terms, which vary from property to property. Consequently, net acreage ownership in these categories is not determinable. Our net interest in production from properties in which we own a royalty or overriding royalty interest may be affected by royalty terms negotiated by the mineral interest owners in such tracts and their lessees. Our interest in the majority of these properties is perpetual in nature. However, a minor portion of the properties are subject to terms and conditions pursuant to which a portion of our interest may terminate upon cessation of production.

The following table sets forth, as of December 31, 2007, the combined summary of total gross and net (where applicable) acres of mineral, royalty, overriding royalty and leasehold interests in each of the states in which these interests are located.

State	Gross	Net	State	Gross	Net
Alabama	106,074	7,797	Missouri	334	43
Arkansas	46,951	15,113	Montana	281,991	62,630
California	924	162	Nebraska	3,360	257
Colorado	22,880	1,424	New Mexico	44,530	2,194
Florida	88,832	24,249	New York	23,077	18,440
Georgia	3,676	1,024	North Dakota	293,614	37,201
Illinois	4,729	885	Oklahoma	228,655	15,999
Indiana	303	113	Pennsylvania	9,511	4,653
Kansas	13,981	2,385	South Dakota	14,408	1,266
Kentucky	1,995	553	Texas	1,637,822	134,507
Louisiana	133,408	1,670	Utah	5,937	200
Michigan	54,367	2,623	Wyoming	28,128	1,057
Mississippi	72,036	8,417			

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Leasing Activity

We received cash payments in the amount of $609,000 during 2007 attributable to lease bonus on 101 leases and six pooling elections in lands located in 27 counties and parishes in six states. These leases reflected bonus payments ranging up to $500/acre and initial royalty terms ranging up to 40%. Many of these leases contain additional overriding royalty interests and provisions for optional working interest participation in subsequent wells, back-in working interests after payout or escalating royalty terms.

We received cash payments in the amount of $172,000 during the fourth quarter of 2007 attributable to lease bonus on 14 leases and three pooling elections of our interests in lands located in 16 counties and parishes in two states. These leases reflected bonus payments ranging up to $500/acre and initial royalty terms ranging up to 40%.

The following table sets forth a summary of leases and pooling elections consummated during 2005 through 2007.

	2007	2006	2005
Consummated Leases			
Number	107	76	78
Number of States	6	7	5
Number of Counties	27	33	26
Average Royalty	24.1%	25.5%	24.8%
Average Bonus, $/acre	$ 222	$ 528	$ 309
Total Lease Bonus cash basis	$ 609,000	$ 7,377,000	$ 1,680,000

Eight leases were granted for no bonus consideration in 2007, which reflected royalty terms ranging from 25% to 40%. Average bonus and royalty terms reflected above include these eight leases. Five leases were granted in 2007, which included (in addition to royalty or bonus) an overriding royalty interest, back-in working interest or optional working interest participation. Average royalty terms reflected above do not reflect these additional interests. Amounts reflected above may differ from our consolidated financial statements, which are presented on an accrual basis. Average royalty and average bonus exclude amounts attributable to pooling elections. Payments received for gas storage, shut-in and delay rental payments, coal royalty, surface use agreements, litigation judgments and settlement proceeds are reflected in our consolidated financial statements in various categories including, but not limited to, other operating revenues and other income.

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, New York, areas which some industry press reports suggest may be prospective for gas production from unconventional reservoirs including the Marcellus Shale. We have engaged in discussions regarding these lands but have not reached an agreement concerning a lease or other transaction. We will continue to monitor industry activity to determine the proper course of action to represent the partnership s interests.

Net Profits Interests

We own net profits overriding royalty interests (referred to as the Net Profits Interests) in various properties owned by the operating partnership. 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 costs 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.

We own four separate Net Profits Interests, all of which were created in connection with the combination in 2003. Three of these Net Profits Interests have been in a continuous profit status other than temporary deficits in that revenues have exceeded costs and cash payments have been made by the operating partnership to us each quarter. 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

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Minerals NPI (previously the 2003-2006 NPI), has continuously had costs that exceed revenues. As of December 31, 2007, 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, production sales volumes and prices, and oil and gas reserves set forth in other portions of this annual report do not reflect amounts attributable to the Minerals NPI, which includes, among other properties, all of the operating partnership s Fayetteville Shale working interest properties in Arkansas.**

The following tables set forth cash receipts and disbursements, production volumes and reserves attributable to the Minerals NPI for the calendar years 2003 through 2007.

	Minerals NPI Cash Basis Results Year Ended December 31, (in Thousands)					
	2003 (11 mo.)	2004	2005	2006	2007	Total
Cash received for revenue	$ 4	$ 1,007	$ 1,447	$ 2,487	$ 3,255	$ 8,200
Cash paid for operating costs	5	146	249	452	521	1,373
Cash paid for development costs	316	1,218	1,086	1,691	2,635	6,946
Net cash (paid) received	$ (317)	$ (357)	$ 112	$ 344	$ 99	$ (119)
Cumulative NPI Deficit		$ (674)	$ (562)	$ (218)	$ (119)	

The revenue amounts, the production volumes, and the proved reserves presented include only properties producing revenue. The development cost amounts pertain to more properties than the properties producing revenue due to timing differences between operating partnership expenditures and oil and gas production and payments to the operating partnership.

	Minerals NPI Cash Basis Production Year ended December 31,					
	2003 (11 mo.)	2004	2005	2006	2007	Total
Natural Gas mcf	259	138,398	126,167	190,903	291,278	747,005
Oil & Condensate bbl	101	5,014	9,434	17,447	19,662	51,658
Indicated Gas Price, $/mcf	$ 3.92	$ 5.96	$ 7.37	$ 7.26	$ 6.58	$ 6.77
Indicated Oil/Condensate Price, $/bbl	$ 28.55	$ 36.05	$ 54.58	$ 61.05	$ 62.93	$ 58.10

The indicated prices set forth above are calculated by dividing each year s gross revenues for each product by the production volume of the corresponding product. Cash received for revenue includes minor amounts of non-product revenue. Such calculation does not necessarily reflect contractual terms for sales and may be affected by transportation costs, location differentials, quality and gravity adjustments and timing differences between production and cash receipts, including release of suspended funds, initial payments for accumulated sales, or prior period adjustments.

	Minerals NPI Reserves Year ended December 31,				
	2003	2004	2005	2006	2007
Proved Reserves (1)					
Natural Gas (mmcf)	231	273	313	532	1,442

Oil & Condensate (mbbls)	5	7	32	46	34
Future Net Revenues ($ in thousands)	$ 906	$ 1,352	$ 3,399	$ 4,309	$ 10,523
Standardized Measure ($ in thousands)	$ 618	$ 1,033	$ 2,655	$ 3,405	$ 7,253

(1) All reserves are proved developed.

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Amounts in the above tables 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 the subject properties. The above production sales volumes, indicated prices, oil and gas reserves, and 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 Interests payment may begin from the Minerals NPI.

The Minerals NPI includes numerous opportunities for the operating partnership to participate as a working interest owner in drilling activity on lands in which we owned a mineral or royalty interest as of the date such Minerals NPI was created. Most of these opportunities are evidenced by a contractual option, but not the obligation, to participate in activity located in defined lands and leases, although some arise by non-contractual means or by operation of law. With regard to the opportunities evidenced by a contractual option, the operating partnership s decision to exercise these options and participate as a working interest owner is made on a well-by-well basis and only in the event a third party proposes to drill a well subject to the contractual option. With regard to the opportunities to participate as a working interest owner that arise non-contractually or by operation of law, we obtain or are provided those opportunities due to the actions of persons that we do not control. Thus, we are unable to project when wells may be drilled, whether the operating partnership may elect to participate, or otherwise end up participating, in such drilling or the magnitude of the corresponding investment, either individually or in the aggregate, with respect to the Minerals NPI. In the event the operating partnership does elect to participate pursuant to these options, or otherwise ends up so participating per force of certain non-contractual relationships or by operation of law, the Minerals NPI deficit is likely to increase. Regardless of the operating partnership s future voluntary or involuntary participation, we believe net profits interest payments, if any, made upon the Minerals NPI s first reaching profit status will be minimal as development of these properties, and consequently the operating partnership s payments of development expenditures associated therewith, is likely to continue for at least five years. See the discussion under Drilling Activity below for additional information on some of these working interest participation options and possibilities.

Acreage Summary

The following tables set forth, as of December 31, 2007, information concerning properties owned by the operating partnership and subject to the Net Profits Interests, including the Minerals NPI properties. Acreage amounts listed under Leasehold reflect gross acres leased by the operating partnership and the working interest share (net acres) in those properties. Acreage amounts listed under Mineral reflect gross acres in which the operating partnership owns a mineral interest and the undivided mineral interest (net acres) in those properties. The operating partnership s interest in these properties may be unleased, leased by others or a combination thereof. Acreage amounts may not add across due to overlapping ownership among categories.

	Mineral	Royalty	Leasehold	Total
Number of States	11	1	6	12
Number of Counties/Parishes	49	1	9	51
Gross Acres	46,025	640	108,947	155,612
Net Acres	5,286		83,864	89,150

The following table reflects the states in which the acreage amounts listed above are located.

	Mineral/Royalty		Leasehold		Total	
	Gross	Net	Gross	Net	Gross	Net
Oklahoma	9,093	808	79,861	74,031	88,954	74,839
Kansas	640	20	7,035	7,035	7,675	7,055
Arkansas	559	326	19,787	2,637	20,346	2,963
All Others	36,373	4,132	2,264	161	38,637	4,293
Totals	46,665	5,286	108,947	83,864	155,612	89,150

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The operating partnership owns working interests below the currently producing horizons in 47,360 gross/46,960 net acres in Texas County, Oklahoma. The operating partnership has from time to time farmed out its leasehold interests in portions of these lands, reserving an overriding royalty interest therein, and will consider additional exploration or development of these lands as circumstances warrant. The leasehold acreage includes all of the acreage in the Fayetteville Shale properties of Arkansas in which we have the right to participate.

Costs Incurred

The following table sets forth information regarding 100% of the costs incurred on a cash basis by the operating partnership during the periods indicated in connection with the properties underlying the Net Profits Interests.

	Years ended December 31,		
	2007	2006	2005
		(in thousands)	
Acquisition costs	$	$	$
Development costs [1]	3,821	1,963	1,295
Total	$ 3,821	$ 1,963	$ 1,295

(1) The years ended December 31, 2005, 2006 and 2007 include $1,086,000, $1,691,000 and $2,647,000 respectively, attributable to NPIs not yet in pay status.

Productive Well Summary

The following table sets forth, as of December 31, 2007, the combined number of producing wells on the properties subject to the Net Profits Interests, including the Minerals NPI. Gross wells refer to wells in which a working interest is owned. Net wells are determined by multiplying gross wells by the working interest in those wells.

	Productive Wells/Units[1]	
Location	Gross	Net
Oklahoma	192	119.5
Kansas	20	20.0
All others	137	8.0
Total	349	147.5

(1) Multiple well units operated by someone other than the operating partnership and in which we own Net Profits Interests are included as one gross well.

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Drilling Activity

We received division orders for or otherwise identified 346 new wells completed on our Royalty Properties in 11 states during 2007. Twenty-four new wells were completed and we identified eight wells that were completed in prior years on our Net Profits Interests properties, all located in seven states during 2007, with six additional wells in various stages of drilling or completion operations at year-end. 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:

					DMOLP		Test Rates per day	
Well Name	**ST**	**County/ Parish**	**Operator**	**DMLP NRI[(2)]**	**WI[(1)]**	**NRI[(2)]**	**Gas, mcf**	**Oil, bbls**
Jerome Carr #2-31H	AR	Conway	SEECO, Inc.	2.2%	3.8%	2.8%	3,242	
Polk 9-15 #1-30H	AR	Conway	SEECO, Inc.	5.9%	5.0%	4.2%	1,614	
Mulliniks 9-12 #1-35H	AR	Cleburne	SEECO, Inc.	3.5%	5.0%	4.4%	3,491	
Hillis #3-27H	AR	Van Buren	SEECO, Inc.	0.0%	6.3%	6.3%	1,856	
Raiders #3-27H	OK	Ellis	Crusader Energy	0.0%	3.8%	9.1%	1,063	367
Schou #1-10	OK	Roger Mills	Apache Corp.	3.6%			4,872	3
Coates A-36	TX	Hidalgo	El Paso E & P Co.	6.4%			13,334	167
Coates-Dorchester #3	TX	Hidalgo	Dan A. Hughes Co.	6.3%	6.3%	4.7%	4,209	70
Coates A-37	TX	Hidalgo	El Paso E & P Co.	6.4%			1,771	15
Southwest Texas Corp #9	TX	Starr	EOG Resources	5.1%			8,177	273
Southwest Texas Corp #8	TX	Starr	EOG Resources	5.1%			5,169	136
Cleopatra #5	TX	Starr	Petrohawk Energy Corp.	1.6%			10,350	86
Cleopatra #7	TX	Starr	Petrohawk Energy Corp.	1.6%			7,573	65
Cleopatra #8	TX	Starr	Petrohawk Energy Corp.	1.6%			6,087	
Harris #1-8	TX	Wheeler	Questar	6.3%			2,511	33
Hink 3-1	TX	Wheeler	Dominion OK TX Expl.	12.5%			1,282	
R N Beyers Unit 2307	TX	Wheeler	Noble Energy Inc.	3.1%			3,119	18

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

Additional information concerning selected recent activity is summarized below:

Jeffress (Vicksburg S) Field, Hidalgo County, Texas We own varying undivided mineral interests in several thousand acres in the greater Jeffress Field area of western Hidalgo County, Texas. We leased our interest in approximately 417 acres to Dan A. Hughes Company in October 2005 for a 25% royalty interest. In addition, the operating partnership was granted a 5% overriding royalty interest which was convertible to a 25% working interest at payout of the first well. The operating partnership has the option, but not the obligation, to participate for a 25% working interest in all future wells drilled on the 417-acre tract or within a surrounding area comprising approximately 1,000 acres. The Coates-Dorchester #1 reached payout in July 2006, at which time we elected to convert our overriding royalty interest to a working interest. Pursuant to the agreement, we elected to participate with a working interest in the Coates-Dorchester #2 well in 2006 and the Coates-Dorchester #3 well, which was drilled to a depth of 10,500 feet in April 2007. The Coates-Dorchester #3 well was completed in the Vicksburg formation and tested at rates of 4,209 mcf and 70 bbls per day. By November 2007, production from this well had declined to average rates of 1,944 mcf and 35 bbls per day. We own a 6.25% net revenue interest in these three wells while the operating partnership owns an additional 4.69% net revenue interest.

T-Patch (Reklaw OSO) Field, Jim Hogg and Starr Counties, Texas We own varying undivided mineral interests totaling 6,524/2,128 gross/net acres in multiple tracts in Jim Hogg and Starr Counties, Texas that we leased to EOG Resources, Inc. (EOG) in 2004 and 2006. EOG completed ten wells on these lands in 2004, 2005 and 2006. In 2007, EOG drilled and completed two additional wells on these lands. The Southwest Texas Corp #8 well was drilled in March 2007 to a permitted total depth of 10,200 feet and was tested to sales at rates

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of 5,169 mcf and 136 bbls per day in April 2007. The Southwest Texas Corp #9 well was drilled in June 2007 to a total depth of 10,500 feet and was tested at rates of 8,177 mcf and 273 bbls per day in July 2007. By November 2007, production from each of these wells had declined to an average rate of approximately 1,042 mcf per day. EOG drilled a thirteenth well that was a dry hole. We own a 5.1% net revenue interest in these wells.

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. In June 2006, we leased our average 8.6% mineral interest in 179 sections in these eight counties for lease bonus payment of approximately $625 per acre, 25% royalty and five-year primary terms. Assuming all of the leased lands are pooled into 640 acre units, we will own an average 2.1% net royalty interest in each well drilled in these units. Actual net royalty interests will vary widely from this average interest based on our actual ownership in each unit. In addition to the basic lease terms, the operating partnership has the option, but not the obligation, to participate for an average 3.5% net working interest in wells drilled on 111 of the 179 sections covered by the leasing agreements. Wells have been proposed, permitted or drilled in 36 of the 184 sections in which we own an interest in this trend.

Fifty-six wells have been permitted on these lands as of February 15, 2008, of which the operating partnership has an interest in thirty-two. In total, 43 wells have been spud, 38 have been completed as producers and six are in various stages of drilling or completion operations. One well was abandoned early in the drilling process due to mechanical issues but was re-drilled and successfully completed as a producer. Set forth below is a summary of activity through February 15, 2008, for wells in which we own a royalty interest or a net profits interest:

	2004	2005	2006	2007	01/01/08-02/15/08	Total
New Well Permits	1	2	11	34	8	56
Wells Spud	0	1	9	33	0	43
Wells Completed	0	1	5	23	9	38
Royalty Wells in Pay Status (1)	0	0	0	5	5	

(1) Royalty Wells in Pay Status means wells for which cash was received during the indicated period attributable to Royalty Properties production.

Our estimated proved reserves as of December 31, 2007, include reserves attributable to our royalty interest in 19 wells totaling 741 mmcf. These wells have average gross ultimate reserves of 1.6 bcf per well. Our estimated reserves do not include amounts attributable to working interests in these or other wells located in this trend and subject to the Minerals NPI as that NPI is in a deficit status.

Net cash receipts for the Royalty Properties attributable to interests in these lands totaled $253,000 in 2007, including $130,000 during the fourth quarter from five wells.

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Oil and Natural Gas Reserves

The following table reflects the Partnership s proved developed and total proved reserves, future net revenues and Standardized Measure at December 31, 2005, 2006 and 2007. The reserves and future net revenues are based on the reports of the independent petroleum engineering consulting firms of Calhoun, Blair & Associates and Huddleston & Co., Inc. Other than those filed with the SEC, our estimated proved reserves have not been filed with or included in any reports to any federal agency.

	2007			2006			2005		
	Royalty Properties	Net Profits Interest[1]	Total	Royalty Properties	Net Profits Interest[1]	Total	Royalty Properties	Net Profits Interest[1]	Total
Proved reserves									
Natural gas (mmcf)	29,555	31,700	61,255	31,363	34,435	65,798	28,965	37,334	66,299
Oil (mbbls)	3,501	65	3,566	3,727	75	3,802	3,948	81	4,029
Future net revenues ($, in thousands)	$ 483,262	$ 121,503	$ 604,765	$ 344,893	$ 113,682	$ 458,575	$ 404,950	$ 214,430	$ 619,380
Standardized Measure [2] ($, in thousands)	$ 233,513	$ 82,854	$ 316,367	$ 169,260	$ 76,899	$ 246,159	$ 201,107	$ 142,574	$ 343,681

(1) Reserves, revenues and present values reflect 96.97% of the corresponding amounts assigned to the operating partnership s interests in the properties underlying the Net Profits Interests.

(2) We do not reflect a federal income tax provision since our partners include the income of our Partnership in their respective federal income tax returns.

Proved oil and gas reserves means the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (a) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ; (b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Title to Properties

We believe we have satisfactory title to all of our assets. Record title to essentially all our assets has undergone the appropriate filings in the jurisdictions in which such assets are located. Title to property may be subject to encumbrances. We believe that none of such encumbrances should materially detract from the value of

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our properties or from our interest in these properties or should materially interfere with their use in the operation of our business.

ITEM 3. LEGAL PROCEEDINGS

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. 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 resolution by the District Court of the operating partnership s counterclaim. An adverse 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 financial position or operating results.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF UNITHOLDERS

No matters were submitted to a vote of unitholders during the fourth quarter of the year ended December 31, 2007.

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PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units began trading on the NASDAQ National Market (now the NASDAQ Global Select Market) on February 3, 2003. The following summarizes the high and low sales information for the common units for the period indicated. The information below reflects inter-dealer prices without retail mark-up, mark-down or commission and may not necessarily represent actual transactions.

	2007		2006	
	High	**Low**	**High**	**Low**
First Quarter	$ 23.10	$ 20.52	$ 29.00	$ 23.00
Second Quarter	$ 24.05	$ 21.27	$ 28.25	$ 23.80
Third Quarter	$ 24.09	$ 18.50	$ 29.30	$ 23.75
Fourth Quarter	$ 23.45	$ 19.00	$ 26.70	$ 21.40

As of December 31, 2007, there were 10,361 common unitholders.

Beginning with the quarter ended March 31, 2003, as required by our partnership agreement, we distributed and will continue to distribute, on a quarterly basis, within 45 days of the end of the quarter, all of our available cash. Available cash means all cash and cash equivalents on hand at the end of that quarter, less any amount of cash reserves that our general partner determines is necessary or appropriate to provide for the conduct of its business or to comply with applicable laws or agreements or obligations to which we may be subject.

Since our Partnership s combination on January 31, 2003, unitholder cash distributions per common unit have been:

	Per Unit Amount				
	2003	**2004**	**2005**	**2006**	**2007**
First Quarter	$ 0.206469	$ 0.415634	$ 0.481242	$ 0.729852	$ 0.461146
Second Quarter	$ 0.458087	$ 0.415315	$ 0.514542	$ 0.778120	$ 0.473745
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 2004 were paid on 28,240,431 units; previous distributions were paid on 27,040,431 units. Fourth quarter distributions are paid in February of the following calendar year to unitholders of record in January or February of such following year. The partnership agreement requires the next cash distribution to be paid by May 15, 2008.

Please see Fourth Quarter 2007 Distribution Indicated Price discussion contained in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Distributions for production periods and cash receipts and weighted average prices corresponding to the fourth quarter 2007 distribution.

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Performance Graph

The following graph compares the performance of our common units with the performance of the NASDAQ Composite Index (the NASDAQ Index) and a peer group index from the first day of trading of our common units, February 3, 2003, through December 31, 2007. The graph assumes that at the beginning of the period, $100 was invested in each of (1) our common units, (2) the NASDAQ Index, and (3) the peer group, and that all distributions or dividends were reinvested. We do not believe that any published industry or line-of-business index accurately reflects our business. Accordingly, we have created a special peer group index consisting of companies whose royalty trust units are publicly traded on the New York Stock Exchange. Our peer group index includes the units of the following companies: Cross Timbers Royalty Trust, Mesa Royalty Trust, Sabine Royalty Trust, Permian Basin Royalty Trust, Hugoton Royalty Trust and the San Juan Basin Royalty Trust.

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ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA
Basis of Presentation

The combination of Republic, Spinnaker and Dorchester Hugoton occurred on January 31, 2003. As a result, the historic data presented for fiscal year ended December 31, 2003 consists of 11 months of our Partnership s results. This table should be read in conjunction with the consolidated financial statements and related notes included elsewhere in this document.

	Fiscal Year Ended December 31, (in thousands, except per unit data)				
	2007	2006	2005	2004	2003
Total operating revenues	$ 65,365	$ 74,927	$ 79,832	$ 57,028	$ 49,358
Depreciation, depletion and amortization	15,567	18,470	20,858	20,795	23,639
Impairment					43,804
Net earnings (loss)	43,048	50,210	52,775	30,076	(26,827)
Net earnings (loss) per unit	1.48	1.72	1.82	1.07	(1.02)
Cash distributions[(1)]	57,401	82,295	58,028	47,701	50,798
Cash distributions per unit[(1)]	1.97	2.83	2.00	1.70	1.94
Total assets	154,251	168,429	200,830	206,173	198,951
Total liabilities	804	629	945	1,035	512
Partners equity	153,447	167,800	199,885	205,138	198,439

(1) Because of depletion (which is usually higher in the early years of production), a portion of every distribution of revenues from properties represents a return of a limited partner s original investment. Until a limited partner receives cash distributions equal to his original investment, in certain circumstances, 100% of such distributions may be deemed to be a return of capital. Cash distributions for 2003 include Dorchester Hugoton s liquidating distribution declared in January 2003. Cash distributions by year exclude the fourth quarter distribution declared in January of the following year, but include the prior year fourth quarter distribution declared in January of the current year.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Critical Accounting Policies

We utilize the full cost method of accounting for costs related to our oil and 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 gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. Our Partnership did not assign any book or market value to unproved properties, including nonproducing royalty, mineral and leasehold interests. The full cost ceiling is evaluated at the end of each quarter and when events indicate possible impairment. For 2003, our unamortized costs of oil and gas properties exceeded the full cost ceiling. As a result, in 2003, our Partnership recorded full cost write-downs of $43,804,000. No additional impairments have been recorded since the quarter ended September 30, 2003.

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

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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 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 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 Net Profits Interests operated by non-affiliated entities are particularly subjective due to the inability to gain accurate and timely information. Therefore, actual results could differ from those estimates. Please see Item 1. Business Customers and Pricing and Item 2. Properties Royalty Properties for additional discussion.

New Accounting Standards

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes. FIN 48 is an interpretation of FASB Statement No. 109, Accounting for Income Taxes and must be adopted no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. We are a pass-through entity and have not experienced an impact on our consolidated financial statements as a result of adoption of FIN 48.

In September 2006, the FASB issued Statement of Accounting Standards No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, expands disclosures about fair value measurements, and is effective for financial statements issued for fiscal years beginning after November 15, 2007, as well as interim periods within those fiscal years. However, the FASB has issued FSP 157-2 to partially defer the effective date for SFAS 157 for one year. The one-year deferral applies to all nonfinancial assets and liabilities (nonfinancial items), except those that are recognized or disclosed at fair value in financial statements on a recurring basis (at least annually). We do not anticipate a material impact on our consolidated financial statements.

Contractual Obligations

Our office lease in Dallas, Texas comprises our contractual obligations.

		Payments due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Operating Lease Obligations	$ 1,721,000	$ 216,000	$ 453,000	$ 477,000	$ 575,000

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Results of Operations

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, and to a lesser extent, by capital expenditures deducted under the Net Profits Interests calculation. Our portion of oil and gas sales volumes and weighted average sales prices are shown in the following table.

	Years Ended December 31,		
	2007	2006	2005
Accrual Basis Sales Volumes:			
Royalty Properties Gas Sales (mmcf)	3,623	3,949	3,890
Royalty Properties Oil Sales (mbbls)	300	329	340
Net Profits Interests Gas Sales (mmcf)	4,133	4,521	4,873
Net Profits Interests Oil Sales (mbbls)	16	15	11
Accrual Basis Weighted Averages Sales Price:			
Royalty Properties Gas Sales ($/mcf)	$ 6.64	$ 6.46	$ 7.43
Royalty Properties Oil Sales ($/bbl)	$ 67.75	$ 59.89	$ 51.07
Net Profits Interests Gas Sales ($/mcf)	$ 6.63	$ 6.28	$ 7.82
Net Profits Interests Oil Sales ($/bbl)	$ 62.40	$ 52.68	$ 50.58
Accrual Basis Production Costs Deducted under the Net Profits Interests ($/mcfe)[1]	$ 1.99	$ 1.57	$ 1.43

(1) Provided to assist in determination of revenues; applies only to Net Profits Interests sales volumes prices.

Comparison of the twelve-month periods ended December 31, 2007, 2006 and 2005

Royalty Properties oil sales volumes decreased 3.2% from 340 mbbls during 2005 to 329 mbbls during 2006 and decreased 8.8% to 300 mbbls during 2007. Royalty Properties gas sales volumes increased 1.5% from 3,890 mmcf during 2005 to 3,949 mmcf during 2006 and then decreased 8.3% to 3,623 mmcf during 2007. Royalty Properties gas sales volumes in 2007 were negatively impacted by weather conditions in the Midcontinent and Gulf Coast regions in the first quarter. These disruptions were temporary in most instances, and royalty gas sales volumes in particular increased by more than 20% from 858 mmcf in the first quarter to 1,035 mmcf in the fourth quarter of 2007.

Net Profits Interests properties oil sales volumes increased 36.4% from 11 mbbls during 2005 to 15 mbbls during 2006 and then increased 6.7% to 16 mbbls during 2007, primarily as a result of improved production in North Dakota properties. Net Profits Interests properties gas sales volumes decreased 7.2% from 4,873 mmcf during 2005 to 4,521 mmcf during 2006 and subsequently decreased 8.6% to 4,133 mmcf in 2007 principally as a result of natural reservoir depletion in the Guymon-Hugoton field in Oklahoma.

Weighted average oil sales prices attributable to the Royalty Properties increased 17.3% from $51.07 per bbl in 2005 to $59.89 per bbl in 2006 and subsequently increased 13.1% to $67.75 per bbl in 2007. Royalty Properties weighted average gas sales prices decreased 13.1% from $7.43 per mcf during 2005 to $6.46 per mcf during 2006 and then increased 2.8% to $6.64 per mcf during 2007. Weighted average Net Profits Interests properties gas sales prices decreased 19.7% from $7.82 per mcf during 2005 to $6.28 per mcf during 2006 and then increased 5.6% to $6.63 per mcf in 2007. Net Profits Interests properties weighted average oil sales prices increased 4.2% from $50.58 per bbl during 2005 to $52.68 per bbl during 2006 followed by an increase of 18.5% to $62.40 per bbl in 2007. All such fluctuations resulted from changing market conditions.

Our 2007 operating revenues decreased 12.8% from $74,927,000 during 2006 to $65,365,000 primarily as a result of decreased lease bonus revenue from 2006, which included an unusual amount of lease bonus income attributable to the Fayetteville Shale transaction. Our 2006 net operating revenues decreased 6.1% from $79,832,000 during 2005 to $74,927,000 primarily as a result of decreased natural gas sales prices.

General and administrative (G&A) costs increased 17.4% from $3,058,000 in 2006 to $3,591,000 in 2007 due to increased costs related to, among other things, increased number of unitholder accounts, modernizing of land records, and outsourcing of royalty revenue processing activities during mid-2006. G&A costs increased slightly from $2,892,000 in 2005 to $3,058,000 in 2006.

Depletion and amortization was $20,858,000 in 2005 and decreased to $18,470,000 and $15,567,000 in 2006 and 2007, respectively, primarily as a result of a lower depletable base due to the effects of previous depletion and upward revisions in oil and gas reserve estimates. Cash flow from operations and cash distributions to unitholders are not affected by depletion, depreciation and amortization.

Net cash provided by operating activities increased 5.3% from $69,112,000 during 2005 to $72,783,000 during 2006 and decreased 19.7% to $58,432,000 during 2007 due primarily to the effects of the unusual amount of Fayetteville Shale lease bonus during 2006 and the timing of cash receipts.

Texas Margin Tax

During 2006, the Texas Legislature 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 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 Item 5. Market for Registrant s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities for the amounts and dates of cash distributions to our 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.

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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).

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to unitholders.

Expenses and Capital Expenditures

The operating partnership s planned drilling of a second Oklahoma Council Grove formation well has been postponed until 2008 due to delayed regulatory permits. The previous Council Grove drilling attempt in 2007 was a dry hole costing approximately $280,000. The 2007 Oklahoma Guymon-Hugoton replacement well increased production from eight to 90 mcf per day and cost approximately $500,000.

During the period beginning in late 2006 through January 2008, the operating partnership deepened four wells into the Fort Riley zone of the Oklahoma Guymon-Hugoton field at costs ranging from $70,000 to $200,000. One well increased from 120 to 319 mcf per day and the remaining wells production was generally unchanged. During 2007, the operating partnership perforated and recompleted two Oklahoma wells into a shallower zone of the Guymon-Hugoton field with mixed results yielding no net production increase and costs ranging from $45,000 to $85,000.

The operating partnership plans to continue its efforts to increase production in Oklahoma by techniques that may include fracture treating, deepening, recompleting, and drilling. As shown above, 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 gas compression and dehydration facilities located in Kansas and Oklahoma. The operating partnership anticipates gradual increases in expenses as repairs to these facilities become more frequent and anticipates gradual increases in field operating expenses as reservoir pressure declines. The operating partnership does not anticipate incurring significant expense to replace these facilities at this time. These capital and operating costs are reflected in the 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. The operating partnership believes it now has sufficient field compression and permits for vacuum operation for the foreseeable future.

Liquidity and Working Capital

Year-end cash and cash equivalents totaled $15,001,000 for 2007, $13,927,000 for 2006, and $23,389,000 for 2005.

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Distributions

Distributions to limited partners and general partners related to cash receipts for the period from October 2006 through December 2007 were as follows:

Year	Quarter	Record Date	Payment Date	Per Unit Amount	Limited Partners	General Partners
					$ in Thousands	
2006	4th	January 30, 2007	February 9, 2007	$ 0.478596	$ 13,516	$ 405
2007	1st	April 23, 2007	May 3, 2007	0.461146	13,023	380
2007	2nd	July 23, 2007	August 3, 2007	0.473745	13,379	402
2007	3rd	October 23, 2007	November 5, 2007	0.560502	15,829	467
Total distributions paid in 2007					$ 55,747	$ 1,654
2007	4th	January 25, 2008	February 4, 2008	$ 0.514625	$ 14,533	$ 463

In general, the limited partners are allocated 96% of the Royalty Properties net receipts and 99% of our Net Profits Interests net receipts.

Net Profits Interests

We receive monthly payments from the operating partnership equal to 96.97% of the net proceeds actually realized by the operating partnership from the properties underlying the Net Profits Interests. The operating partnership retains the 3.03% balance of these net proceeds. Net proceeds generally reflect gross proceeds attributable to oil and natural gas production actually received during the month less production costs actually paid during the same month. Production costs generally reflect drilling, completion, operating and general and administrative costs and exclude depletion, amortization and other non-cash costs. The operating partnership made Net Profits Interests payments to us totaling $21,408,000 during October 2006 through September 2007, which payments reflected 96.97% of total net proceeds of $22,076,000 realized from September 2006 through August 2007. Net proceeds realized by the operating partnership during September through November 2007 were reflected in Net Profits Interests payments made during October through December 2007. These payments were included in the fourth quarter distribution paid in early 2008 and are excluded from this 2007 analysis.

Royalty Properties

Revenues from the Royalty Properties are typically paid to us with proportionate severance (production) taxes deducted and remitted by others. Additionally, we generally pay ad valorem taxes, general and administrative costs, and marketing and associated costs since royalties and lease bonuses generally do not otherwise bear operating or similar costs. After deduction of the above described costs including cash reserves, our net cash receipts from the Royalty Properties during the period October 2006 through September 2007 were $35,993,000, of which $34,553,000 (96%) was distributed to the limited partners and $1,440,000 (4%) of which was distributed to the general partner. Proceeds received by us from the Royalty Properties during the period October through December 2007 became part of the fourth quarter distribution paid in early 2008, which is excluded from this 2007 analysis.

Distribution Determinations

The actual calculation of distributions is performed each calendar quarter in accordance with our partnership agreement. The following calculation covering the period October 2006 through September 2007 demonstrates the method.

	$ In Thousands	
	Limited Partners	**General Partner**
4% of Net Cash Receipts from Royalty Properties	$	$ 1,440
96% of Net Cash Receipts from Royalty Properties	34,553	
1% of Net Profits Interests Paid to our Partnership		214
99% of Net Profits Interests Paid to our Partnership	21,194	
Total Distributions	$ 55,747	$ 1,654
Operating Partnership Share (3.03% of Net Proceeds)		669
Total General Partner Share		$ 2,323
% of Total	96%	4%

In summary, our limited partners received 96%, and our general partner received 4% of the net cash generated by our activities and those of the operating partnership during this period. Due to these fixed percentages, our general partner does not have any incentive distribution rights or other right or arrangement that will increase its percentage share of net cash generated by our activities or those of the operating partnership.

During the period October 2006 through September 2007, our Partnership s quarterly distribution payments to limited partners were based on all of its available cash. Our Partnership s only significant cash reserves that influenced quarterly payments were $1,125,000 for ad valorem taxes. Additionally, certain production costs under the Net Profits Interests calculation and a small portion of management expense reimbursements include amounts for which funds were set aside monthly to enable payment when due. Examples are pension contributions and payroll taxes. These amounts generally are not held for periods over one year.

Fourth Quarter 2007 Distribution Indicated Price

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 contractual terms for such sales and may be affected by transportation costs, location differentials, and quality and gravity adjustments. While the relationship between the Partnership s 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 the Partnership s Royalty Properties during the 2007 fourth quarter totaled $11,168,000. These receipts generally reflect oil sales during September through November 2007 and gas sales during August through October 2007. The weighted average indicated prices for oil and gas sales during the 2007 fourth quarter attributable to the Royalty Properties were $79.72/bbl and $5.99/mcf.

Cash receipts attributable to the Partnership s Net Profits Interests during the 2007 fourth quarter totaled $4,559,000. These receipts generally reflect oil and gas sales from the properties underlying the Net Profits Interests during August through October 2007. The weighted average indicated prices for oil and gas sales during the 2007 fourth quarter attributable to the Net Profits Interests were $68.56/bbl and $5.85/mcf.

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General and Administrative Costs

In accordance with our partnership agreement, we bear all general and administrative and other overhead expenses subject to certain limitations. We reimburse our general partner for certain allocable costs, including rent, wages, salaries and employee benefit plans. This reimbursement is limited to an amount equal to the sum of 5% of our distributions plus certain costs previously paid. Through December 31, 2007, the limitation was substantially in excess of the reimbursement amounts actually paid or accrued.

ITEM 7A. 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 the Net Profits Interests and the Royalty Properties, which generally entitle us to receive a share of the proceeds from oil and natural gas production on 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 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements are set forth herein commencing on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Partnership maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in its filings with the SEC are recorded, processed, summarized and reported within the time period specified in the SEC s rules and forms, and that such information is accumulated and communicated to management, including its chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure based on the definition of disclosure controls and procedures as defined in Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act).

Management s Annual Report on Internal Control Over Financial Reporting

Management acknowledges its responsibility for establishing and maintaining adequate internal control over financial reporting in accordance with Rule 13a-15(f) promulgated under the Exchange Act. Management has

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also evaluated the effectiveness of its internal control over external financial reporting in accordance with generally accepted accounting principles within the guidelines of the Committee of Sponsoring Organizations of the Treadway Commission framework. Based on the results of this evaluation, Management has determined that the Partnership s internal control over financial reporting was effective as of December 31, 2007.

Changes in Internal Controls

There were no changes in our Partnership s internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements and Schedules

(1) See the Index to Consolidated Financial Statements on page F-1.
(2) No schedules are required.
(3) 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 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)

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Number	Description
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)
10.1	Amended and Restated Business Opportunities Agreement dated as of December 13, 2001 by and between the Registrant, the General Partner, Dorchester Minerals Management GP LLC, SAM Partners, Ltd., Vaughn Petroleum, Ltd., Smith Allen Oil & Gas, Inc., P.A. Peak, Inc., James E. Raley, Inc., and certain other parties (incorporated by reference to Exhibit 10.1 to Dorchester Minerals Report on Form 10-K for the year ended December 31, 2002)
10.2	Transfer Restriction Agreement (incorporated by reference to Exhibit 10.2 to Dorchester Minerals Report on Form 10-K for the year ended December 31, 2002)
10.3	Registration Rights Agreement (incorporated by reference to Exhibit 10.3 to Dorchester Minerals Report on Form 10-K for the year ended December 31, 2002)
10.4	Lock-Up Agreement by William Casey McManemin (incorporated by reference to Exhibit 10.4 to Dorchester Minerals Report on Form 10-K for the year ended December 31, 2002)
10.5	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.1 to Dorchester Minerals Report on Form 10-Q for the quarter ended June 30, 2004)
21.1*	Subsidiaries of the Registrant
23.1*	Consent of Grant Thornton LLP
23.2*	Consent of Calhoun, Blair & Associates
23.3*	Consent of Huddleston & Co., Inc.
31.1*	Certification of Chief Executive Officer of our Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer of our Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
32.1*	Certification of Chief Executive Officer of our Partnership pursuant to 18 U.S.C. Sec. 1350
32.2*	Certification of Chief Financial Officer of our Partnership pursuant to 18 U.S.C. Sec. 1350

* Filed herewith

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GLOSSARY OF CERTAIN OIL AND GAS TERMS

The definitions set forth below shall apply to the indicated terms as used in this document. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

bbl means a standard barrel of 42 U.S. gallons and represents the basic unit for measuring the production of crude oil, natural gas liquids and condensate.

bcf means one billion cubic feet under prescribed conditions of pressure and temperature and represents a unit for measuring the production of natural gas.

Depletion means (a) the volume of hydrocarbons extracted from a formation over a given period of time, (b) the rate of hydrocarbon extraction over a given period of time expressed as a percentage of the reserves existing at the beginning of such period, or (c) the amount of cost basis at the beginning of a period attributable to the volume of hydrocarbons extracted during such period.

Division order means a document to protect lessees and purchasers of production, in which all parties who may have a claim to the proceeds of the sale of production agree upon how the proceeds are to be divided.

Enhanced recovery means the process or combination of processes applied to a formation to extract hydrocarbons in addition to those that would be produced utilizing the natural energy existing in that formation. Examples of enhanced recovery include water flooding and carbon dioxide (CO2) injection.

Estimated future net revenues (also referred to as estimated future net cash flow) means the result of applying current prices of oil and natural gas to estimated future production from oil and natural gas proved reserves, reduced by estimated future expenditures, based on current costs to be incurred in developing and producing the proved reserves, excluding overhead.

Formation means a distinct geologic interval, sometimes referred to as the strata, which has characteristics (such as permeability, porosity and hydrocarbon saturations) that distinguish it from surrounding intervals.

Gross acre means the number of surface acres in which a working interest is owned.

Gross well means a well in which a working interest is owned.

Lease bonus means the initial cash payment made to a lessor by a lessee in consideration for the execution and conveyance of the lease.

Leasehold means an acre in which a working interest is owned.

Lessee means the owner of a lease of a mineral interest in a tract of land.

Lessor means the owner of the mineral interest who grants a lease of his interest in a tract of land to a third party, referred to as the lessee.

Mineral interest means the interest in the minerals beneath the surface of a tract of land. A mineral interest may be severed from the ownership of the surface of the tract. Ownership of a mineral interest generally involves four incidents of ownership: (1) the right to use the surface; (2) the right to incur costs and retain profits, also called the right to develop; (3) the right to transfer all or a portion of the mineral interest; and (4) the right to retain lease benefits, including bonuses and delay rentals.

mcf means one thousand cubic feet under prescribed conditions of pressure and temperature and represents the basic unit for measuring the production of natural gas.

mbbls means one thousand standard barrels of 42 U.S. gallons and represents the basic unit for measuring the production of crude oil, natural gas liquids and condensate.

mmcf means one million cubic feet under prescribed conditions of pressure and temperature and represents the basic unit for measuring the production of natural gas.

Net acre means the product determined by multiplying gross acres by the interest in such acres.

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Net well means the product determined by multiplying gross oil and natural gas wells by the interest in such wells.

Net profits interest means a non-operating interest that creates a share in gross production from another (operating or non-operating) interest in oil and natural gas properties. The share is determined by net profits from the sale of production and customarily provides for the deduction of capital and operating costs from the proceeds of the sale of production. The owner of a net profits interest is customarily liable for the payment of capital and operating costs only to the extent that revenue is sufficient to pay such costs but not otherwise.

Operator means the individual or company responsible for the exploration, development, and production of an oil or natural gas well or lease.

Overriding royalty interest means a royalty interest created or reserved from another (operating or non-operating) interest in oil and natural gas properties. Its term extends for the same term as the interest from which it is created.

Proved developed reserves means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves or *Proved oil and gas reserves* means the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or a conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (b) the immediately adjoining portions not yet drilled but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (a) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ; (b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (c) crude oil, natural gas, and natural gas liquids that may occur in undrilled prospects; and (d) crude oil, natural gas, and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved undeveloped reserves means proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Royalty means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof) but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage.

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Severance tax means an amount of tax, surcharge or levy recovered by governmental agencies from the gross proceeds of oil and natural gas sales. Production tax may be determined as a percentage of proceeds or as a specific amount per volumetric unit of sales. Severance tax is usually withheld from the gross proceeds of oil and natural gas sales by the first purchaser (e.g., pipeline or refinery) of production.

Standardized measure of discounted future net cash flows (also referred to as standardized measure) means the pretax present value of estimated future net revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

Test Rate means a daily volume of oil, gas or condensate at which a well produced to a pipeline or tank battery within that well s first month of production based on information obtained from public sources or from the operator.

Undeveloped acreage means lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Unitization means the process of combining mineral interests or leases thereof in separate tracts of land into a single entity for administrative, operating or ownership purposes. Unitization is sometimes called pooling or communitization and may be voluntary or involuntary.

Working interest (also referred to as an operating interest) means a real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and certain activities in connection with the development and operation of a property.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: March 6, 2008

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ William Casey McManemin
William Casey McManemin

Chief Executive Officer and Manager

(Principal Executive Officer)

Date: March 6, 2008

/s/ H.C. Allen, Jr.
H.C. Allen, Jr.

Chief Financial Officer and Manager

(Principal Financial and Accounting Officer)

Date: March 6, 2008

/s/ James E. Raley
James E. Raley

Chief Operating Officer and Manager

Date: March 6, 2008

/s/ Buford P. Berry
Buford P. Berry

Manager

Date: March 6, 2008

/s/ Preston A. Peak
Preston A. Peak

Manager

Date: March 6, 2008

/s/ C. W. Russell
C. W. Russell

Manager

Date: March 6, 2008

/s/ Ronald P. Trout
Ronald P. Trout

Manager

/s/ Robert C. Vaughn
Robert C. Vaughn

Manager

Date: March 6, 2008	Date: March 6, 2008

DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner and Unitholders

Dorchester Minerals, L.P.

We have audited Dorchester Minerals, L.P. s (a Delaware Limited Partnership) internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Dorchester Minerals, L.P. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Dorchester Minerals, L.P. s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Dorchester Minerals, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Dorchester Minerals, L.P. as of December 31, 2007 and the related consolidated statements of operations, changes in partnership capital, and cash flows for the year then ended, and our report dated March 6, 2008 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Grant Thornton LLP

Dallas, Texas

March 6, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner and Unitholders

Dorchester Minerals, L.P.

We have audited the accompanying consolidated balance sheets of Dorchester Minerals, L.P. (a Delaware Limited Partnership) and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, changes in partnership capital, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Dorchester Minerals, L.P. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Dorchester Minerals, L.P. s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 6, 2008 expressed an unqualified opinion.

/s/ Grant Thornton LLP

Grant Thornton LLP

Dallas, Texas

March 6, 2008

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

CONSOLIDATED BALANCE SHEETS

December 31, 2007 and 2006

(Dollars in Thousands)

	2007	2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,001	$ 13,927
Trade receivables	7,053	6,088
Net profits interests receivable related party	3,576	4,126
Current portion of note receivable related party		50
Total current assets	25,630	24,191
Note receivable related party less current portion		5
Other non-current assets	19	19
Total	19	24
Property and leasehold improvements at cost:		
Oil and natural gas properties (full cost method)	291,830	291,875
Less accumulated full cost depletion	163,582	148,064
Total	128,248	143,811
Leasehold improvements	512	512
Less accumulated amortization	158	109
Total	354	403
Net property and leasehold improvements	128,602	144,214
Total assets	$ 154,251	$ 168,429
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 517	$ 303
Current portion of deferred rent incentive	39	39
Total current liabilities	556	342
Deferred rent incentive less current portion	248	287
Total liabilities	804	629
Commitments and contingencies (Note 4)		
Partnership capital:		
General partner	6,417	6,797
Unitholders	147,030	161,003

Total partnership capital	153,447	167,800
Total liabilities and partnership capital	$ 154,251	$ 168,429

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

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Years Ended December 31, 2007, 2006 and 2005 (Dollars in Thousands, except per unit amounts)

	2007	2006	2005
Operating revenues:			
Royalties	$ 44,398	$ 45,171	$ 46,285
Net profits interests	20,347	22,298	31,801
Lease bonus	575	7,418	1,680
Other	45	40	66
Total operating revenues	65,365	74,927	79,832
Costs and expenses:			
Production taxes	2,093	2,238	2,347
Operating expenses	1,774	1,820	1,261
Depreciation, depletion and amortization	15,567	18,470	20,858
General and administrative expenses	3,591	3,058	2,892
Total costs and expenses	23,025	25,586	27,358
Operating income	42,340	49,341	52,474
Other income, net	708	869	301
Net earnings	$ 43,048	$ 50,210	$ 52,775
Allocation of net earnings:			
General Partner	$ 1,274	$ 1,520	$ 1,427
Unitholders	$ 41,774	$ 48,690	$ 51,348
Net earnings per common unit (basic and diluted)	$ 1.48	$ 1.72	$ 1.82
Weighted average common units outstanding (000 s)	28,240	28,240	28,240

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

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2007, 2006 and 2005

(Dollars in Thousands)

	2007	2006	2005
Cash flows from operating activities:			
Net earnings	$ 43,048	$ 50,210	$ 52,775
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation, depletion and amortization	15,567	18,470	20,858
Write-off related to unsuccessful acquisition	57		57
Amortization of deferred rent	(39)	(39)	(40)
Changes in operating assets and liabilities:			
Trade receivables	(965)	1,527	(2,226)
Net profits interests receivable related party	550	2,870	(2,246)
Prepaid expenses		22	(16)
Accounts payable and other current liabilities	214	(277)	(50)
Net cash provided by operating activities	58,432	72,783	69,112
Cash flows from investing activities:			
Proceeds from note receivable related party	55	50	50
Capital expenditures	(12)		(110)
Net cash provided by (used in) investing activities	43	50	(60)
Cash flows from financing activities:			
Distributions paid to partners	(57,401)	(82,295)	(58,028)
Increase (decrease) in cash and cash equivalents	1,074	(9,462)	11,024
Cash and cash equivalents at beginning of year	13,927	23,389	12,365
Cash and cash equivalents at end of year	$ 15,001	$ 13,927	$ 23,389

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

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERSHIP CAPITAL

For the Years Ended December 31, 2007, 2006, and 2005

(Dollars in Thousands)

Year		General Partner	Unitholders	Total
2005				
	Balance at January 1, 2005	$ 7,807	$ 197,331	$ 205,138
	Net earnings	1,427	51,348	52,775
	Distributions ($1.999147 per Unit)	(1,571)	(56,457)	(58,028)
	Balance at December 31, 2005	7,663	192,222	199,885
2006				
	Net earnings	1,520	48,690	50,210
	Distributions ($2.829597 per Unit)	(2,386)	(79,909)	(82,295)
	Balance at December 31, 2006	6,797	161,003	167,800
2007				
	Net earnings	1,274	41,774	43,048
	Distributions ($1.973989 per Unit)	(1,654)	(55,747)	(57,401)
	Balance at December 31, 2007	$ 6,417	$ 147,030	$ 153,447

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

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2007 2006 and 2005

1. General and Summary of Significant Accounting Policies

Nature of Operations In these Notes, the term Partnership, as well as the terms us, our, we, and its are sometimes used as abbreviated refere to Dorchester Minerals, L.P. itself or Dorchester Minerals, L.P. and its related entities. Our Partnership is a Dallas, Texas based owner of producing and nonproducing natural gas and crude oil royalty, net profits, and leasehold interests in 573 counties and 25 states. We are a publicly traded Delaware limited partnership that was formed in December 2001, and commenced operations on January 31, 2003.

Basis of Presentation 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 per unit do not differ.

Principles of Consolidation 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.

Reclassification Certain amounts in the 2005 consolidated financial statements have been reclassified to conform to the 2006 and 2007 presentation.

Estimates 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 consolidated 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. See Item 1. Business Customers and Pricing and Item 2. Properties Royalty Properties for additional discussion.

The discounted present value of our proved oil and 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. 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. See the discussion under *Property and Equipment*.

General Partner Our general partner is Dorchester Minerals Management LP, referred to in these Notes as our general partner. Our general partner owns all of the partnership interests in Dorchester Minerals Operating LP, the operating partnership. See Note 3 Related Party Transactions. The general partner is allocated 1% and 4% of our Net Profits Interests revenues and Royalty Properties revenues, respectively. Our executive officers all own an interest in our general partner and receive no compensation for services as officers of our Partnership.

Cash and Cash Equivalents Our principal banking is with major financial institutions. Cash balances in these accounts may, at times, exceed federally insured limits. We have not experienced any losses in such cash

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2007, 2006 and 2005

accounts and do not believe we are exposed to any significant risk on cash and cash equivalents. Short term investments with a maturity of three months or less are considered to be cash equivalents and are carried at cost, which approximates fair value. Other income includes interest earned on short term investments of $578,000, $696,000, and $349,000 in 2007, 2006, and 2005, respectively.

Concentration of Credit Risks Our Partnership, as a royalty owner, has no control over the volumes or method of sale of oil and natural gas produced and sold from the Royalty Properties. It is believed that the loss of any single customer would not have a material adverse effect on the consolidated results of our operations.

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 year-end or that will be realized in the future.

Trade Receivables Our Partnership s trade receivables consist primarily of Royalty Properties payments receivable and Net Profits Interests payments receivable. Most payments are received two to four months after production date. No allowance for doubtful accounts is deemed necessary.

Note Receivable Related Party Our Note Receivable consisted of a five-year note payable by Dorchester Minerals Operating LP, referred to in these Notes as the operating partnership, bearing interest at 6% having an original amount of $250,836. Principal and interest payments were received quarterly. The note was paid in full at December 31, 2007.

Property and Equipment We utilize the full cost method of accounting for costs related to our oil and 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 gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. Our Partnership did not assign any value to unproved properties, including nonproducing royalty, mineral and leasehold interests. The full cost ceiling is evaluated at the end of each quarter and when events indicate possible impairment.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and 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 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.

Our Partnership s properties are being depleted on the unit-of-production method using estimates of proved oil and gas reserves. Gains and losses are recognized upon the disposition of oil and gas properties involving a significant portion (greater than 25%) of our Partnership s reserves. Proceeds from other dispositions of oil and gas properties are credited to the full cost pool. No gains or losses have been recorded for 2007, 2006 or 2005.

Leasehold improvements include $415,000 received in 2004 as an incentive in our office space lease and is offset in liabilities as deferred rent. Leasehold improvements are amortized over the shorter of their estimated

DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2007, 2006 and 2005

useful lives or the related lease life of 10 years. For leases with renewal periods at the Partnership s option, we have used the original lease term, excluding renewal option periods to determine useful life. Deferred rent incentive is being amortized to general and administrative expense over the same term as the leasehold improvements, which is 10 years.

Asset Retirement Obligations Based on the nature of our property ownership we have no material obligation required to be recorded.

Revenue Recognition The pricing of oil and natural gas sales from the Royalty Properties is primarily determined by supply and demand in the marketplace and can fluctuate considerably. As a royalty owner, we have extremely limited involvement and operational control over the volumes and method of sale of oil and natural gas produced and sold from the Royalty Properties.

Revenues from Royalty Properties and Net Profits Interests are recorded under the cash receipts approach as directly received from the remitters statement accompanying the revenue check. Since the revenue checks are generally received two to four months after the production month, the Partnership accrues for revenue earned but not received by estimating production volumes and product prices.

Income Taxes We are treated as a partnership for income tax purposes and, as a result, our income or loss is includible in the tax returns of the individual unitholders. Unitholders should consult tax advisors concerning their own tax situation. Depletion of natural gas properties is an expense allowable to each individual partner, and the depletion expense as reported on the consolidated financial statements will not be indicative of the depletion expense an individual partner or unitholder may be able to deduct for income tax purposes.

New Accounting Pronouncements In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes. FIN 48 is an interpretation of FASB Statement No. 109, Accounting for Income Taxes and must be adopted no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. We are a pass-through entity and have not experienced an impact on consolidated financial statements as a result of adoption of FIN 48.

In September 2006, the FASB issued Statement of Accounting Standards No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, expands disclosures about fair value measurements, and is effective for financial statements issued for fiscal years beginning after November 15, 2007, as well as interim periods within those fiscal years. However, the FASB has issued FSP 157-2 to partially defer the effective date for SFAS 157 for one year. The one-year deferral applies to all nonfinancial assets and liabilities (nonfinancial items), except those that are recognized or disclosed at fair value in financial statements on a recurring basis (at least annually). We do not anticipate a material impact on our consolidated financial statements.

2. Acquisitions

On May 2, 2005, we filed a registration statement on Form S-4 with the Securities and Exchange Commission to register 5,000,000 common units that may be offered and issued by the Partnership from time to time in connection with asset acquisitions or other business combination transactions. As of March 6, 2008, none of the 5,000,000 units have been offered.

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2007, 2006 and 2005

3. Related Party Transactions

Our general partner owns all of the partnership interests in the operating partnership. It is the employer of all personnel, owns the working interests and other properties underlying our Net Profits Interests, and provides day-to-day operational and administrative services to us and the general partner. In accordance with our partnership agreement, we reimburse the general partner for certain allocable general and administrative costs, including rent, salaries, and employee benefit plans. These types of reimbursements are limited to 5% of distributions, plus certain costs previously paid. All such costs have been substantially below the 5% limit amount. Additionally, certain reimbursable direct costs such as professional and regulatory fees and ad valorem and severance taxes, are not limited. Significant activity between the partnership and the operating partnership consists of the following:

	Thousands of Dollars		
From/To Operating Partnership	**2007**	**2006**	**2005**
Net Profits Interests Payments Receivable or Accrued[1]	$ 3,576	$ 4,126	$ 6,996
Note Receivable	$	$ 55	$ 105
Interest Income related to Net Profits Interests Payments	$ 1	$ 8	$ 6
General & Administrative Amounts Payable	$ 52	$ 40	$ 86
General & Administrative Amounts Accrued	$ 31	$ 23	$ 19
Total General & Administrative Amounts	$ 2,365	$ 2,088	$ 1,716

(1) All Net Profits Interests income on the financial statements is from the operating partnership.

Less than $15,000 in fees for legal services were paid in 2007, 2006 and 2005 to a family member of a member of our executive management.

4. Commitments and 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. 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 resolution by the District Court of the operating partnership s counterclaim. An adverse decision could reduce amounts we receive from the Net Profits Interests.

Our 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.

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2007, 2006 and 2005

Operating Leases We have entered into a non-cancelable, renewable at prevailing rate for an additional five years, operating lease agreement in the ordinary course of our business activities. The lease is for our office space at 3838 Oak Lawn Avenue, Suite 300, Dallas, Texas, and expires in 2015. Rental expense related to the lease, including operating expenses and consumption of electricity, was $199,000, $174,000, and $203,000 for the years ended December 31, 2007, 2006, and 2005, respectively. The base rent escalates in October, 2008 and October, 2010. Minimum rental commitments under the terms of our operating lease are as follows:

Years Ended December 31,	Minimum Payments
2008	$ 216,000
2009	225,000
2010	228,000
2011	237,000
2012	240,000
Thereafter	575,000
Total	$ 1,721,000

5. Distribution To Holders Of Common Units

Unitholder cash distributions per common unit have been:

	Per Unit Amount		
	2005	2006	2007
First Quarter	$ 0.481242	$ 0.729852	$ 0.461146
Second Quarter	$ 0.514542	$ 0.778120	$ 0.473745
Third Quarter	$ 0.577287	$ 0.516082	$ 0.560502
Fourth Quarter	$ 0.805543	$ 0.478596	$ 0.514625

Distributions were paid on 28,240,431 units. Fourth quarter distributions are paid in February of the following calendar year to unitholders of record in January or February of such following year. The partnership agreement requires the next cash distribution to be paid by May 15, 2008.

6. Unaudited Oil and Natural Gas Reserve and Standardized Measure Information

The Net Profits Interests represent net profits overriding royalty interests in various properties owned by the operating partnership. The Royalty Properties consist of producing and nonproducing mineral, royalty, overriding royalty, net profits, and leasehold interests located in 573 counties and parishes in 25 states. Amounts set forth herein attributable to the Net Profits Interests reflect our 96.97% net share. Although new discoveries have occurred on certain of the Royalty Properties, based on engineering studies available to date, no events have occurred since December 31, 2007 that would have a material effect on our estimated proved developed reserves.

In accordance with SFAS No. 69 and Securities and Exchange Commission rules and regulations, the following information is presented with regard to the Net Profits Interests and Royalty Properties oil and gas reserves, all of which are proved, developed and located in the United States. These rules require inclusion as a supplement to the basic financial statements a standardized measure of discounted future net cash flows relating to proved oil and gas reserves. The standardized measure, in management s opinion, should be examined with

DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2007, 2006 and 2005

caution. The basis for these disclosures is petroleum engineers reserve studies which contain imprecise estimates of quantities and rates of production of reserves. Revision of prior year estimates can have a significant impact on the results. Also, exploration and production improvement costs in one year may significantly change previous estimates of proved reserves and their valuation. Values of unproved properties and anticipated future price and cost increases or decreases are not considered. Therefore, the standardized measure is not necessarily a best estimate of the fair value of oil and gas properties or of future net cash flows.

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves. The production volumes and reserve volumes included for properties formerly owned by Dorchester Hugoton are wellhead volumes, which differ from sales volumes shown in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations because of fuel, shrinkage and pipeline loss. The Standardized Measure of Discounted Future Net Cash Flows reflects adjustments for such fuel, shrinkage and pipeline loss.

Summary of Changes in Proved Reserves

	Oil (mbbl)			Natural Gas (mmcf)		
	2007	2006	2005	2007	2006	2005
Estimated quantity, beginning of year	3,802	4,029	3,937	65,798	66,299	69,459
Purchase of minerals in place						
Revisions in previous estimates	80	117	443	3,721	8,467	6,128
Production	(316)	(344)	(351)	(8,264)	(8,968)	(9,288)
Estimated quantity, end of year	3,566	3,802	4,029	61,255	65,798	66,299

Standardized Measure of Discounted Future Net Cash Flows

(Dollars in Thousands)

	2007	2006	2005
Future estimated gross revenues	$ 636,734	$ 482,053	$ 651,583
Future estimated production costs	(31,969)	(23,478)	(32,203)
Future estimated net revenues	604,765	458,575	619,380
10% annual discount for estimated timing of cash flows	(288,398)	(212,416)	(275,699)
Standardized measure of discounted future estimated net cash flows	$ 316,367	$ 246,159	$ 343,681
Sales of oil and natural gas produced, net of production costs	$ (60,877)	$ (63,410)	$ (74,477)
Net changes in prices and production costs	87,896	(71,241)	90,466
Revisions of previous quantity estimates	16,083	25,458	33,375
Accretion of discount	24,616	34,368	25,459

Change in production rate and other		2,490		(22,697)		14,271
Net change in standardized measure of discounted future estimated net cash flows	$	70,208	$	(97,522)	$	89,094
Depletion of oil and natural gas properties (dollars per mcfe)	$	1.53	$	1.67	$	1.83
Property acquisition costs	$		$		$	

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DORCHESTER MINERALS, L.P.

(A Delaware Limited Partnership)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2007, 2006 and 2005

7. Unaudited Quarterly Financial Data

Quarterly financial data for the last two years (in thousands except per unit data) is summarized as follows:

	2007 Quarter Ended				2006 Quarter Ended			
	March 31	June 30	Sept. 30	Dec. 31	March 31	June 30	Sept. 30	Dec. 31
Net operating revenues	$ 14,714	$ 17,613	$ 14,716	$ 18,322	$ 19,267	$ 23,128	$ 16,897	$ 15,635
Net earnings	$ 9,123	$ 12,082	$ 9,474	$ 12,369	$ 13,060	$ 16,789	$ 10,392	$ 9,969
Net earnings per Unit (basic and diluted)	$ 0.31	$ 0.42	$ 0.33	$ 0.42	$ 0.45	$ 0.58	$ 0.36	$ 0.33
Weighted average common units outstanding	28,240	28,240	28,240	28,240	28,240	28,240	28,240	28,240