DORCHESTER MINERALS LP
Form 10-K
February 24, 2011
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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, 2010

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ 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 $619,551,146 as of June 30, 2010, based on $25.53 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 February 24, 2011: 30,675,431

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the registrant s 2011 Annual Meeting of Unitholders to be held on May 11, 2011, 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, 2010.

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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 and its 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 established an Internet website at www.dmlp.net that 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 LP owns working interests and other properties underlying our Net Profits Interests (or NPIs), 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 general partner and the operating partnership are Delaware limited partnerships, and the general partners of their general partners are Delaware limited liability companies. These entities and our Partnership were initially formed in December 2001 in connection with the combination. Our wholly owned subsidiary, Dorchester Minerals Oklahoma LP and its general partner are Oklahoma entities that acquired our wholly owned acquisition subsidiary and its general partner by merger on December 31, 2009. On March 31, 2010, we formed a new subsidiary, and it acquired all of the outstanding partnership interests in Maecenas Minerals LLP, a Texas limited liability partnership.

Our business may be described as the acquisition, ownership and administration of Royalty Properties and NPIs. The Royalty Properties consist of producing and nonproducing mineral, royalty, overriding royalty, net profits, and leasehold interests located in 574 counties and parishes in 25 states. The NPIs represent net profits overriding royalty interests in various properties owned by the operating partnership.

Our partnership agreement requires that we distribute quarterly an amount equal to all funds that we receive from the Royalty Properties and the NPIs 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

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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. We have an effective registration statement on Form S-4 registering 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, 2,565,000 units remain available.

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;
- 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;

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- 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 a Williams entity (currently Williams Gas Marketing, Inc.) on a daily market price basis using a yearly contract that will continue through October 2011. The operating partnership frequently reviews alternative gas purchasers. We believe that the loss of Williams 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.

Business Opportunities Agreement

Pursuant to a business opportunities agreement among us, our general partner, the general partner of our general partner, the owners of the general partner of our general partner (the GP Parties), and, in their individual capacities as officers of the general partner of our general partner, William Casey McManemin, James E. Raley and H.C. Allen, Jr., we have agreed that, except with the consent of our general partner, which it may withhold in its sole discretion, we will not engage in any business not permitted by our partnership agreement, and we will have no interest or expectancy in any business opportunity that does not consist exclusively of the oil and natural gas business within a designated area that includes portions of Texas County, Oklahoma and Stevens County, Kansas. All opportunities that are outside the designated area or are not oil and natural gas business activities, are called renounced opportunities.

The parties also have agreed that, as long as the activities of the general partner, the GP Parties and their affiliates or manager designees are conducted in accordance with specified standards, or are renounced opportunities:

- our general partner, the GP Parties and their affiliates or the manager designees will not be prohibited from engaging in the oil and natural gas business or any other business, even if such activity is in direct or indirect competition with our business activities;

affiliates of our general partner, the GP Parties and their affiliates and the manager designees will not have to offer us any business opportunity;

we will have no interest or expectancy in any business opportunity pursued by affiliates of our general partner, the GP Parties or their affiliates and the manager designees; and

we waive any claim that any business opportunity pursued by our general partner, the GP Parties or their affiliates and the manager designees constitutes a corporate opportunity that should have been presented to us.

The standards specified in the business opportunities agreement generally provide that the GP Parties and their affiliates and manager designees must conduct their business through the use of their own personnel and assets and not with the use of any personnel or assets of us, our general partner or operating partnership. A manager designee or personnel of a company in which any affiliate of our general partner or any GP Party or their affiliates has an interest or in which a manager designee is an owner, director, manager, partner or employee (except for our general partner and its general partner and their subsidiaries) is not allowed to usurp a business opportunity solely for his or her personal benefit, as opposed to pursuing, for the benefit of the separate party an opportunity in accordance with the specified standards.

In certain circumstances, if a GP Party or any subsidiary thereof, any officer of the general partner of our general partner or any of their subsidiaries, or a manager of the general partner of our general partner that is an affiliate of a GP Party signs a binding agreement to purchase oil and natural gas interests, excluding oil and natural gas working interests, then such party must notify us prior to the consummation of the transactions so that we may determine whether to pursue the purchase of the oil and natural gas interests directly from the seller. If we do not pursue the purchase of the oil and natural gas interests or fail to respond to the purchasing party s notice within the provided time, the opportunity will also be considered a renounced opportunity.

In the event any GP Party or one of their subsidiaries acquires an oil and natural gas interest, including oil and natural gas working interests, in the designated area, it will offer to sell these interests to us within one month of completing the acquisition. This obligation also applies to any package of oil and natural gas interests, including oil and natural gas working interests, if at least 20% of the net acreage of the package is within the designated area; however, this obligation does not apply to interests purchased in a transaction in which the procedures described above were applied and followed by the applicable affiliate.

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;

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- 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 24, 2011, the operating partnership had 20 full-time employees in our Dallas, Texas office and seven 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.

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.

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We do not control operations and development of the Royalty Properties or the properties underlying the NPIs 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 NPI 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 NPIs. 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 NPIs are under no obligation to continue operating the underlying properties. The operating partnership can sell any of the properties underlying the NPIs that it operates and relinquish the ability to control or influence operations. Any such sale or transfer must also simultaneously include the NPIs 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.

Significant portions 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 NPIs.

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

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 NPIs 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 NPIs, 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

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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 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 by the operating partnership 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 such as NPIs 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 us 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 NPIs, 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.

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 NPIs, the costs of unsuccessful future drilling on the working interest properties that are subject to the NPIs will reduce amounts payable to us under the NPIs 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 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.

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 NPIs are geographically concentrated, which could cause net proceeds payable under the NPIs to be impacted by regional events.

The vast majority of the properties subject to the NPIs 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 NPIs more than if the properties were more geographically diversified.

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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 NPIs, much of the economic risk of the underlying properties is passed along to us.

Under the terms of the NPIs, 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 NPIs. However, except as described below, we are not required to pay any excess costs.

The terms of the NPIs 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 us not receiving any payments under the NPIs until all prior uncharged costs have been recovered by the operating partnership.

Damages 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 damages from these operations would be production costs under the terms of the NPIs 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.

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 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 NPIs 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

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Oklahoma and Kansas, where properties that are subject to the NPIs 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 NPIs. 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 NPIs would be deducted from amounts payable to us under the NPIs.

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.

Federal hydraulic fracturing legislation could delay or restrict development of our oil and natural gas properties.

During the last Congressional Session, several bills were proposed that would have subjected the process of hydraulic fracturing to regulation under the Safe Drinking Water Act. Similar legislation may be proposed by the current Congress. In addition, the EPA s Office of Research and Development (ORD) is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. The ORD expects to have the initial study results available by late 2012. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate production. The use of hydraulic fracturing is necessary to produce commercial quantities of crude oil and natural gas from many reservoirs. Although it is not possible at this time to predict the final outcome of the ORD s study and any resulting legislation, any new federal restrictions on hydraulic fracturing could significantly increase operating, capital and compliance costs. Such cost increases could delay or restrict development by operators of our oil and natural gas properties.

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

To date, Congress has not passed a bill specifically addressing greenhouse gas (GHG) regulation. However, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an Endangerment Finding under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has issued final regulations requiring petroleum and natural gas operators meeting a certain emission threshold to report their greenhouse gas emissions to the EPA. The EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future greenhouse gas emission limits. Although it is not possible at this time to predict whether or when Congress may act on climate change legislation, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require the operating partnership and oil and natural gas operators that develop our properties to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas produced from our properties.

Our oil and natural 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.

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

Our general partner may withdraw or 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 our common units; 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.

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Our 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

The tax consequences to a unitholder of the ownership and sale of common units will depend in part on the unitholder s tax circumstances. Each unitholder should, therefore, consult such unitholder s own tax advisor about the federal, state and local tax consequences of the ownership of common units.

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 and possibly certain state corporate income or franchise taxes 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

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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.

If we were taxable as a corporation for federal income tax purposes, we may also be subject to additional state-level corporate income or franchise taxes.

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 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 NPIs 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, unrealized 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.

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 of a sale or other transfer of common units, and a proper transfer of ownership is not recorded on the appropriate books and records, 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.

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.

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

The Proposed Fiscal Year 2011and 2012 Federal Budgets include proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration activities. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the repeal of the domestic manufacturing tax deduction for oil and natural gas companies, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available to our unitholders and to oil and natural gas operators that we rely upon to develop our properties. Such legislation or changes could negatively impact both our unitholders and our Partnership financially.

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 sir 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

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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.

Properties

We own two categories of properties: Royalty Properties and Net Profits Interests (NPIs).

Royalty Properties

We own Royalty Properties representing producing and nonproducing mineral, royalty, overriding royalty, net profits and leasehold interests in properties located in 574 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, 2010, 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	17	8	25
Number of Counties/Parishes	465	190	137	34	574
Gross Acres	2,308,024	616,541	208,755	36,527	3,119,528
Net Acres (where applicable)	377,707				377,707

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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, 2010, 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
Alabama	105,192	7,794
Arkansas	47,219	15,646
California	1,451	162
Colorado	22,880	1,424
Florida	88,832	25,267
Georgia	3,676	1,285
Illinois	4,729	885
Indiana	303	142
Kansas	13,981	2,388
Kentucky	1,995	678
Louisiana	131,075	2,520
Michigan	54,234	2,623
Mississippi	72,026	8,622
State	**Gross**	**Net**
Missouri	344	43
Montana	281,890	62,850
Nebraska	3,360	287
New Mexico .	42,410	2,814
New York	23,077	18,863
North Dakota	292,771	46,073
Oklahoma	230,400	16,973
Pennsylvania .	9,513	5,631
South Dakota	14,407	1,266
Texas	1,641,199	151,955
Utah	5,937	200
Wyoming	26,627	1,316

Leasing Activity

The operating partnership and we received cash payments in the amount of $3,862,000 during 2010 attributable to lease bonus on 97 leases and six pooling elections in lands located in 32 counties and parishes in eight states. These leases reflected bonus payments ranging up to $5,010/acre and initial royalty terms ranging up to 26%.

The operating partnership and we received cash payments in the amount of $22,000 during the fourth quarter of 2010 attributable to lease bonus on nine leases of our interests in lands located in five counties and parishes in four states. These leases reflected bonus payments ranging up to $2,000/acre and initial royalty terms ranging up to 25%.

The following table sets forth a summary of leases and pooling elections consummated during 2008 through 2010.

	2010	2009	2008

Consummated Leases			
Number	103	53	51
Number of States	8	4	4
Number of Counties	32	22	19
Average Royalty	24.8%	23.4%	25.0%
Average Bonus, $/acre	$ 1,705	$ 565	$ 398
Total Lease Bonus cash basis	$ 3,862,000	$ 663,000	$ 441,000

Amounts reflected above may differ from our consolidated financial statements, which are presented on an accrual basis. Some activity may be in Net Profits Interests income. 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.

Net Profits Interests

We own net profits overriding royalty interests (referred to as the Net Profits Interests, or NPIs) 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 six separate NPIs. Four were created in connection with the combination in 2003, one immaterial Net Profits Interest was subsequently created and is currently in deficit, and one was acquired with the acquisition of Maecenas Minerals LLP on March 31, 2010. Four of these NPIs 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 NPIs 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. The Net Profits Interest referred to as the Minerals NPI has continuously had costs that exceed revenues. As of December 31, 2010, 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 NPIs that are in a deficit status. **Consequently, net profits interest payments, production sales volumes and prices, and oil and natural gas reserves set forth in other portions of this annual report do not reflect amounts attributable to the Minerals NPI, which includes all of the operating partnership s Fayetteville Shale working interest properties in Arkansas.**

The following tables set forth cash receipts and disbursements, production volumes and reserves attributable to the Minerals NPI from inception through 2005 and the calendar years 2006 through 2010.

Minerals NPI Cash Basis Results
Year Ended December 31, (in Thousands)

	Inception Through 2005	2006	2007	2008	2009	2010	Total
Cash received for revenue	$ 2,458	$ 2,487	$ 3,255	$ 6,016	$ 3,408	$ 7,901	$ 25,525
Cash paid for operating costs	400	452	521	853	865	1,732	4,823
Cash paid for development costs	2,620	1,691	2,635	4,778	4,348	3,249	19,321
Budgeted capital expenditures				905	890	2,630	4,425
Net cash (paid) received	$ (562)	$ 344	$ 99	$ (520)	$ (2,695)	$ 290	$ (3,044)
Cumulative NPI Deficit	$ (562)	$ (218)	$ (119)	$ (639)	$ (3,334)	$ (3,044)	

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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 natural gas production and payments to the operating partnership.

	Minerals NPI Cash Basis Production Year ended December 31,						
	Inception through 2005	2006	2007	2008	2009	2010	Total
Natural Gas mcf	264,824	190,903	291,278	418,743	596,341	957,176	2,719,265
Oil & Condensate bbl	14,549	17,447	19,662	22,480	21,104	53,369	148,611
Indicated Gas Price, $/mcf		$ 7.26	$ 6.58	$ 8.55	$ 3.74	$ 4.13	$ 5.45
Indicated Oil/Cond. Price, $/bbl		$ 61.05	$ 62.93	$ 100.98	$ 48.80	$ 71.52	$ 68.08

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.

All Proved Developed and Located in the United States	Minerals NPI Reserves Year ended December 31,						
	2004	2005	2006	2007	2008	2009	2010
Proved Reserves							
Natural Gas (mmcf)[1]	273	313	532	1,442	1,993	3,016	4,260
Oil & Condensate (mbbls)[1]	7	32	46	34	65	65	178
Future Net Revenues ($ in thousands)[1]	$ 1,352	$ 3,399	$ 4,309	$ 10,523	$ 9,341	$ 8,950	$ 30,353
Standardized Measure ($ in thousands)[1]	$ 1,033	$ 2,655	$ 3,405	$ 7,253	$ 6,533	$ 6,451	$ 14,025

(1) Based on 12-month unweighted arithmetic average of the first day-of-the-month price of oil and natural gas in 2009 forward, otherwise based on year-end pricing of oil and natural gas

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 natural 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 NPI payments 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

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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 balance is likely to increase. Regardless of the operating partnership s future voluntary or involuntary participation, we believe initial net profits interest payments made upon the Minerals NPI s first reaching profit status, if any, will be insignificant due to our expectation that the operating partnership will continue to incur development expenditures for at least the next 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, 2010, information concerning properties owned by the operating partnership and subject to the NPIs, 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. In addition to amounts listed below, the operating partnership owns interests limited to certain wellbores located on lands in which we own mineral, royalty or leasehold interests. The acreage amounts associated with the wellbore interests are included in Royalty Properties Acreage Summary and not in the table below.

	Mineral	Royalty	Leasehold	Total
Number of States	12	2	6	12
Number of Counties/Parishes	60	2	13	66
Gross Acres	49,188	640	110,673	160,501
Net Acres	7,260		84,272	91,532

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	11,200	955	80,181	74,056	91,381	75,011
Kansas	640	20	7,035	7,035	7,675	7,055
Arkansas	679	308	19,787	2,637	20,466	2,945
All Others	37,309	5,977	3,670	544	40,979	6,521
Totals	49,828	7,260	110,673	84,272	160,501	91,532

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.

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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 NPIs.

	Years ended December 31,		
	2010	2009	2008
	(in thousands)		
Acquisition costs	$	$	$
Development costs[1]	3,268	4,377	5,315
Total	$ 3,268	$ 4,377	$ 5,315

(1) The years ended December 31, 2008, 2009 and 2010 include $4,793,000, $4,348,000 and $3,249,000, respectively, attributable to NPIs not yet in pay status.

Productive Well Summary

The following table sets forth, as of December 31, 2010, the combined number of producing wells on the properties subject to the NPIs, 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	201	120.3
Kansas	20	20.0
All others	323	15.3
Total	544	155.6

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

Drilling Activity

We received division orders for or otherwise identified 348 new wells completed on our Royalty Properties in 10 states during 2010. Fifty-seven new wells were completed on our NPI properties in 2010. We identified eight wells that were completed in prior years, and an additional 20 wells were 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 below.

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

					DMOLP		Test Rates per day	
ST	County/ Parish	Operator	Well Name	DMLP NRI(2)	WI(1)	NRI(2)	Gas, mcf	Oil, bbls
AR	Logan	Highland Oil & Gas	Gregory #4		3.125%	3.125%	1,355	
AR	Logan	SEECO	Johns #2-4H3		3.084%	3.084%	11,289	
AR	Logan	Highland Oil & Gas	Morris #2		3.125%	3.125%	1,359	
LA	De Soto	Comstock Oil & Gas	HA RA SUA; Collins LA 15 HZ 2-Alt	2.734%			2,033	
MT	Richland	Continental Resources	Carda #3-28H		6.250%	5.938%	91	226
ND	Dunn	ConocoPhillips	Intervale 41-35H	3.728%			257	823
ND	Mountrail	Fidelity Expl & Prod	Deadwood Canyon Ranch 11-33H	0.999%			707	777
ND	Mountrail	Fidelity Expl & Prod	Deadwood Canyon Ranch 44-32H	1.038%			706	904
ND	Mountrail	Fidelity Expl & Prod	Deadwood Canyon Ranch 44-34H	2.011%			636	997
ND	Williams	Brigham Oil & Gas	Owan-Nehring 27-34 1H	0.306%			1,787	2,215
OK	Caddo	St. Mary Land & Expl.	Reiss Trust #1-16		1.319%	1.319%	8,496	
TX	Crockett	Walter Oil & Gas Corp.	Elliott, M #2H		3.301%	3.301%	1,265	
TX	Dawson	Fasken Oil and Ranch	Jacksonville College 9 #1	6.250%			73	147
TX	Hidalgo	Shell Expl & Prod	Woods Christian #48	2.734%			1,518	
TX	San Jacinto	Famcor Oil, Inc.	Vann #3	2.500%			1,700	
TX	Starr	RAM Operating	Garza Hitchcock #19	2.653%			2,187	
TX	Starr	Cactus Rose, LLC	Guerra #2	7.041%				197
TX	Tarrant	Chesapeake Operating	Duck Lake #8H	17.063%			3,971	
TX	Tarrant	Chesapeake Operating	Duck Lake #10H	17.063%			3,456	
TX	Tarrant	Chesapeake Operating	Duck Lake #11H	17.063%			3,507	
TX	Wood	Energy Prod Corp.	SASI Ranch #2 SX	3.223%			115	421

(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.

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Additional information concerning selected recent activity is summarized below:

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. Two hundred eighty-nine wells have been permitted on the lands as of December 31, 2010, of which the operating partnership has an interest in 182. In total, 254 wells had been spud, 219 had been completed as producers and 20 were in various stages of drilling or completion operations. Wells that have been proposed to be drilled by the operator but for which permits have not yet been issued by the Arkansas Oil & Gas Commission are not reflected in this number. Available test results for wells completed in 2010, along with ownership interests owned by us and interests owned by the operating partnership subject to the Minerals NPI, are summarized in the following table.

			DMLP	DMOLP		Gas Test Rates
County	**Operator**	**Well Name**	**NRI(2)**	**WI(1)**	**NRI(2)**	**Mcf per day**
Conway	SEECO	Bryant 9-15 #5-32H30	4.793%	4.722%	3.579%	5,385
Conway	SEECO	Criswell 8-14 #2-29H	1.563%	1.250%	0.938%	4,627
Conway	Chesapeake Operating	Georgia Brown 8-16 #1-36H	5.859%	5.100%	3.830%	2,725
Conway	Chesapeake Operating	Govan 7-15 #1-6H	2.263%	4.237%	3.187%	4,015
Conway	SEECO	Howell 7-16 #1-1H	2.354%	4.394%	3.295%	3,878
Conway	Chesapeake Operating	Merideth 7-16 #2-2H	0.781%			7,257
Conway	SEECO	Polk 9-15 #5-30H	5.930%	5.561%	4.245%	3,334
Conway	SEECO	William Gray 7-15 #1-18H	0.781%			6,487
Faulkner	SEECO	Krisell Trust 7-14 #1-3H	2.340%	4.758%	3.576%	6,451
Faulkner	Chesapeake Operating	Lagasse Investments Inc. 8-12 #1-8H	7.617%	5.000%	3.750%	1,559
Faulkner	Chesapeake Operating	Lagasse Investments Inc. 8-12 #2-8H	7.617%			1,823
Faulkner	Chesapeake Operating	Lagasse Investments Inc. 8-12 #3-8H	7.617%			2,096
Faulkner	Chesapeake Operating	Lane 8-12 #1-8H	7.617%	5.000%	3.750%	1,018
Faulkner	Chesapeake Operating	Lane 8-12 #2-8H	7.617%	5.000%	3.750%	1,842
Faulkner	SEECO	Ralph Taylor 8-12 #1-20H	2.461%	4.844%	3.633%	1,879
Van Buren	SEECO	Alice Mobbs 10-13 #1-19H	1.552%	1.242%	0.931%	6,950
Van Buren	SEECO	Betty Graddy Trust 10-12 #7-15H16	1.479%	2.366%	1.775%	4,267
Van Buren	SEECO	David Brown 9-13 #3-13H24	0.918%	1.486%	1.119%	5,242
Van Buren	SEECO	Hillis 10-16 #5-27H		6.250%	6.250%	1,853
Van Buren	XTO Energy	Roe Reynolds 9-12 #1-27H22	3.105%	3.312%	2.484%	2,015
White	SEECO	Riley 9-6 #1-22H	3.125%	5.000%	3.750%	1,716
White	SEECO	Riley 9-6 #3-22H15	2.649%	4.238%	3.179%	4,359
White	SEECO	Riley 9-6 #4-22H15	2.508%	4.014%	3.010%	4,352
White	SEECO	Riley 9-6 #5-22H15	2.676%	4.282%	3.212%	3,413

(1) WI means the working interest owned by the operating partnership and subject to the Minerals NPI.

(2) NRI means the net revenue interest attributable to our royalty interest or to the operating partnership s royalty and working interest, which is subject to the Minerals NPI.

Set forth below is a summary of Fayetteville Shale activity through December 31, 2010 for wells in which we have a royalty or Net Profits Interest. This includes wells subject to the Minerals NPI, which is currently in deficit status.

	2004 through 2007	2008	2009	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Total to Date
New Well Permits	47	66	69	23	19	31	34	289
Wells Spud	41	62	70	23	15	26	17	254

Wells with First Production	27	53	49	13	33	18	26	219
Royalty Wells in Pay Status[(1)]	6	30	54	10	14	20	25	159

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

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Our estimated proved reserves as of December 31, 2010, include reserves attributable to our royalty interest in 195 wells totaling 4.05 bcf. Proved reserves attributable to working interests owned by the operating partnership totaled 3.74 bcf in 127 wells. These estimates only include wells for which test rates have been obtained.

Net cash receipts for the Royalty Properties attributable to interests in these lands totaled $2,609,000 in 2010 from 159 wells. Net cash receipts for the Minerals NPI properties attributable to interests in these lands totaled $2,458,000 in 2010 from 85 wells. Fourth quarter net cash receipts for the Royalty Properties and the Minerals NPI properties totaled $706,000 from 158 wells and $578,000 from 83 wells, respectively.

Horizontal Bakken, Williston Basin We own varying undivided perpetual mineral interests totaling 70,390/8,905 gross/net acres located in Burke, Divide, Dunn, McKenzie, Mountrail and Williams Counties, North Dakota. Operators active in this area include Continental Resources, EOG Resources, Hess Corporation, Marathon Oil Company, and Whiting Oil & Gas. There have been a total of 62 wells permitted on these lands as of December 31, 2010 with 97 completed as producers. In virtually all cases we have elected not to lease our lands and not to pay our share of well costs, thus becoming a non-consenting mineral owner. According to North Dakota law, non-consenting owners receive the average royalty rate from the date of first production and back-in for their full working interest after the operator has recovered 150% of drilling and completion costs. Once 150% payout occurs, the working interest will be owned by the operating partnership and subject to the Minerals NPI. Non-consenting owners are not entitled to well data other than public information available from the North Dakota Industrial Commission. As of December 31, 2010, six of these wells had achieved 150% payout.

Set forth below is a summary of Horizontal Bakken activity through December 31, 2010 for wells in which we have a royalty or Net Profits Interest. This includes wells subject to the Minerals NPI, which is currently in a deficit status.

	2004 through 2007	2008	2009	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Total to Date
New Well Permits	17	45	22	6	18	6	18	132
Wells Spud	14	26	31	7	16	12	9	115
Wells Completed	9	22	32	9	6	12	7	97
Wells in Pay Status[1]	0	3	1	1	0	1	0	6

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

Appalachian Basin We own varying undivided perpetual mineral interests in approximately 31,000/24,000 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, an area which some industry press reports suggest may be prospective for gas production from unconventional reservoirs, including the Marcellus Shale. The New York State Department of Environmental Conservation has restricted permitting in the Marcellus shale pending a regulatory review of high-volume hydraulic fracturing practices. Development of these natural gas resources will be limited until this regulatory issue has been resolved. We continue to monitor industry activity and encourage dialogue with industry participants to determine the proper course of action regarding our interests in this area.

Barnett Shale We own producing and nonproducing mineral and royalty interests located in Tarrant County, Texas. The properties consist of varying undivided mineral and overriding royalty interests in six tracts totaling approximately 1,820 acres in what is commonly referred to as the Core Area of the Barnett Shale Trend. All of the mineral interests were leased in 2003 to a predecessor of Chesapeake Energy Corporation, the current operator of and majority working interest owner in the properties. Approximately 577 acres of the subject lands are pooled into six units totaling 1,800 acres; approximately 1,129 acres are developed on a lease basis and the remaining lands are leased but not pooled or drilled upon. As of December 31, 2010, 40 wells were drilled from

11 padsites located on or adjacent to the properties, of which 32 wells were completed for production and eight were drilled but not yet completed or connected to a pipeline. Permits to drill four additional wells on the properties had been issued by regulatory agencies.

Granite Wash, Texas Panhandle We own varying undivided perpetual mineral interests totaling 16,336/2,559 gross/net acres in Hemphill, Roberts and Wheeler Counties, Texas. Operators active in this area include Apache Corporation, Chesapeake Operating, Forest Oil, Linn Energy, Newfield Exploration, and QEP Resources. In 2010, we leased 680 net acres to two parties in two transactions for 25% royalty and total bonus consideration of $2,892,560. As of December 31, 2010, two horizontal well permits had been granted on the leased lands.

Oil and Natural Gas Reserves

The following table reflects the Partnership s proved developed and total proved reserves at December 31, 2010. The reserves are based on the reports of two independent petroleum engineering consulting firms: Calhoun, Blair & Associates and LaRoche Petroleum Consultants, Ltd. As described above, the Partnership does not have information that would be available to a company with oil and natural gas operations because detailed information is not generally available to owners of royalty interests. The Partnership s engineering manager gathers production information and provides such information to our two independent engineering consulting firms who extrapolate from such information estimates of the reserves attributable to the Royalty Properties and NPIs based on their expertise in the oil and natural gas fields where the Royalty Properties and NPIs are situated, as well as publicly available information. Ensuring compliance with generally accepted petroleum engineering and evaluation methods and procedures is the responsibility of the Partnership s engineering manager. Our engineering manager has a bachelor s degree in Petroleum Engineering from the University of Alberta and has worked in the upstream oil and natural gas business in various capacities since 1996. The engineering manager reports directly to the chief executive officer. Our chief executive officer ensures compliance with SEC guidance. He received his Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1984 and has been a Registered Professional Engineer in Texas since 1988. Calhoun Blair & Associates is registered with the Engineering Board of the State of Texas and has been engaged in the business of oil and natural gas property evaluation since 1998. LaRoche Petroleum Consultants, Ltd. is registered with the Engineering Board of the State of Texas. The LaRoche Firm has been engaged in the business of oil and natural gas property evaluation since its formation in 1979. 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. Copies of the reports prepared by Calhoun, Blair & Associates and LaRoche Petroleum Consultants, Ltd. are attached hereto as Exhibits 99.1 and 99.2.

Summary of Oil and Gas Reserves as of Fiscal Year-End

	All Proved Developed and located in the United States					
	Royalty Properties		Net Profits Interests[1]		Total	
Reserves Category	Oil (mbbls)	Natural Gas (mmcf)	Oil (mbbls)	Natural Gas (mmcf)	Oil (mbbls)	Natural Gas (mmcf)
2010	3,290	36,931	43	24,748	3,333	61,679
2009	3,237	34,923	40	25,357	3,277	60,280
2008[2]	3,514	32,028	56	28,949	3,570	60,977

(1) Reserves reflect 96.97% of the corresponding amounts assigned to the operating partnership s interests in the properties underlying the Net Profits Interests.
(2) Based on year-end oil and natural gas prices

Proved oil and natural 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., 12 month unweighted arithmetic average of the first day of the month prices and costs as of the date the estimate is made. Previously, year-end pricing and costs were used. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations for average sales prices.

The Hugoton Field reflected in the Net Profits Interests above is the only significant field, defined as more than 15% of total proved developed reserves. Hugoton Field production (not sales) for the last three years is listed below:

Production by Significant Field

	Numbers in Thousands	
	MCF	BOE
2010	3,656	609
2009	3,945	658
2008	4,240	707

Title to Properties

We believe we have satisfactory title to all of our assets. Record title to essentially all of 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 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 NPI amounts paid to us. On April 9, 2007, plaintiffs, for immaterial costs, dismissed with prejudice all claims against the operating partnership regarding such residential gas use. On October 4, 2004, the plaintiffs filed severed claims against the operating partnership regarding royalty underpayments, which the Texas County District Court subsequently dismissed with a grant of time to replead. On January 27, 2006, one of the original plaintiffs again sued the operating partnership for underpayment of royalty, seeking class action certification. On October 1, 2007, the Texas County District Court granted the operating partnership s motion for summary judgment finding no royalty underpayments. Subsequently, the District Court denied the plaintiff s motion for reconsideration, and the plaintiff filed an appeal. On March 31, 2010, the appeal decision reversed and remanded to the Texas County District Court to resolve material issues of fact. A hearing regarding the requested class action certification is set for late July, 2011. No court hearing has been scheduled on the merits. An adverse decision could reduce amounts we receive from the NPIs.

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. [REMOVED AND RESERVED]

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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.

	2010		2009	
	High	Low	High	Low
First Quarter	$ 23.86	$ 20.50	$ 20.40	$ 14.37
Second Quarter	$ 28.15	$ 21.04	$ 23.03	$ 16.05
Third Quarter	$ 27.30	$ 23.66	$ 25.78	$ 21.06
Fourth Quarter	$ 29.42	$ 25.00	$ 23.85	$ 20.01

As of December 31, 2010, there were 14,777 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.

Unitholder cash distributions per common unit for the past four years have been:

	Per Unit Amount			
	2010	2009	2008	2007
First Quarter	$ 0.449222	$ 0.401205	$ 0.572300	$ 0.461146
Second Quarter	$ 0.412207	$ 0.271354	$ 0.769206	$ 0.473745
Third Quarter	$ 0.471081	$ 0.286968	$ 0.948472	$ 0.560502
Fourth Quarter	$ 0.354074	$ 0.321540	$ 0.542081	$ 0.514625

Distributions beginning with the first quarter of 2010 were paid on 30,675,431 units; distributions from the second quarter of 2009 through the fourth quarter of 2009 were paid on 29,840,431 units; previous distributions above 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, 2011.

Please see Fourth Quarter 2010 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 2010 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 December 31, 2005 through December 31, 2010. 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.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

Basis of Presentation

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)				
	2010	**2009**	**2008**	**2007**	**2006**
Total operating revenues	$ 61,094	$ 43,631	$ 89,925	$ 65,365	$ 74,927
Depreciation, depletion and amortization	17,988	15,599	14,739	15,567	18,470
Net earnings	34,883	21,681	66,783	43,048	50,210
Net earnings per unit (basic and diluted)	1.11	0.72	2.30	1.48	1.72
Cash distributions(1)	52,198	44,728	81,648	57,401	82,295
Cash distributions per unit(1)	1.65	1.50	2.80	1.97	2.83
Total assets	153,111	152,768	139,562	154,251	168,429
Total liabilities	710	737	980	804	629
Partners capital	152,401	152,031	138,582	153,447	167,800

(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 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.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
2010 Overview

Our results during 2010 were strong despite continued poor natural gas prices and reduced drilling activity in most producing areas. Significant results include the following:

- Net income of $34.9 million;
- Distributions of $50.5 million to our limited partners;
- Identified 360 new wells located on our Royalty and Net Profits Interest Properties in 11 states;
- Consummated 103 leases of our mineral interest in undeveloped properties located in 32 counties and parishes in eight states, and
- Consummated the acquisition of complementary mineral, royalty, and net profits interest properties in exchange for our limited partnership units.

Critical Accounting Policies

We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this method, all such costs are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. 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. No impairments have been recorded since 2003.

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

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of our reserves are objectively determined. Effective December 31, 2009, the ceiling test calculation requires use of the unweighted arithmetic average of the first day of the month price during the 12-month period ending on the balance sheet date and costs in effect as of the last day of the accounting period, which are generally held constant for the life of the properties. As a result, the present value is not necessarily an indication of the fair value of the reserves. Oil and natural gas prices have historically been volatile, and the prevailing prices at any given time may not reflect our Partnership s or the industry s forecast of future prices.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. For example, estimates of uncollected revenues and unpaid expenses from Royalty Properties and NPIs 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.

Contractual Obligations

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

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