DORCHESTER MINERALS, L.P.
Form 10-K
March 08, 2018

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2017
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 or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

3838 Oak Lawn Avenue, Suite 300
Dallas, Texas 75219

(Address of principal executive offices) (Zip Code)

(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 each 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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes No

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 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 (§ 229.405 of this chapter) 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.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	Accelerated filer	Non-accelerated filer (Do not check if a smaller reporting company)

Smaller reporting company	Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

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 $421,073,423 as of June 30, 2017, based on $14.45 per unit, the closing price of the common units as reported on the NASDAQ Global Select Market on such date.

Number of Common Units outstanding as of March 8, 2018: 32,279,774

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the registrant's 2018 Annual Meeting of Unitholders to be held on May 16, 2018, 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, 2017.

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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 6201 15th Avenue, Brooklyn, NY 11219, (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 a 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 our website. We will provide electronic or paper copies of our annual report on Form 10-K, quarterly reports on Form 10-Q, 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 ("Royalty Properties"). 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.

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

- in exchange for our limited partner interests, including common units, not exceeding 20% of the common units outstanding after issuance; or

- in exchange for cash, if the aggregate cost of any acquisitions made for cash during the twelve-month period ending on the first to occur of the execution of a definitive agreement for the acquisition or its consummation is no more than 10% of our aggregate cash distributions for the four most recent fiscal quarters.

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

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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 effective registration statements on Form S-4 registering an aggregate of 8,000,000 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. During 2017, the Partnership issued 1,604,343 common units in connection with the consummation of the transactions contemplated by that certain Contribution, Exchange and Purchase Agreement dated June 28, 2017 between the Partnership and DSD Royalty, LLC and those certain Contribution and Exchange Agreements dated June 30, 2017 between the Partnership and each of 1307, Ltd., SCW Capital, LP, Tortuga Oil & Gas, L.P., Robert R. Penn, Squaretop Partners, L.P., Marshall Bryan Payne, MARI GST Non-Exempt Trust, Vaughn Petroleum (DMLP), LLC, James E. Raley, 2011 Pete & Kay Allen Family Trust, Leslie A. Moriyama, Rokeby Investments, L.P., Browning C. Vaughn, The MDIG PPM Trust, The MDIG WWM Trust, The MDIG AMM Trust, The MDIG SCM Trust and Quiscalus Ventures, LLC. At present, 6,395,657 units remain available under the Partnership’s registration statements on Form S-4.

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

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

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

The operating partnership sells its Oklahoma Hugoton field natural gas production to DCP Midstream, LP, a gas processor and purchaser under a processing and purchase agreement. The agreement is automatically renewed annually unless cancelled by either party. We believe that the loss of DCP Midstream, LP or any single customer would not have a material adverse effect on us due to the availability of alternative purchasers in the area.

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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, and the owners of the general partner of our general partner (the "GP Parties"), 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.

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Operating Hazards and Uninsured Risks

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

- the presence of unanticipated pressure or irregularities in formations;
- accidents;
- title problems;
- weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the delivery of equipment.

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

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

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

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

Employees

As of March 8, 2018, the operating partnership had 24 full-time employees in our Dallas, Texas office and six 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;

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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.

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 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.

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

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

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

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

A significant portion 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.

A significant portion of the properties subject to the NPIs are natural gas properties located in the Hugoton field in Oklahoma. 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.

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, 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 environmental, health, and safety matters. These laws and regulations can have a significant impact on production and costs of production. For example, in Oklahoma, where properties that are subject to the NPIs are located, regulators 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.

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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 have possible 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. Because we do not directly operate our properties, our direct liability under environmental laws is limited. It is likely, however, 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.

The following is a summary of some of the existing environmental laws, rules and regulations that apply to oil and gas operations, and that may indirectly affect our cash flow.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"). CERCLA, also known as the Superfund law, and comparable state statutes impose strict liability, and under certain circumstances, joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. The term "hazardous substance" is specifically defined to exclude petroleum, including crude oil and any fraction thereof, natural gas and natural gas liquids. Despite this exclusion, certain materials that are commonly used in connection with oil and gas operations are considered to be hazardous substances under CERCLA. Responsible persons include the current or former owner or operator of the site where the release occurred, and anyone who disposed of or arranged for the disposal of a hazardous substance released at the site, regardless of whether the disposal of hazardous substances was lawful at the time of the disposal. Under CERCLA, such persons may be subject to strict, joint and several liabilities for the costs of investigating releases of hazardous substances, cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The operators of our properties may be responsible under CERCLA for all or part of these costs. Although we are not an operator, our ownership of royalty interests could cause us to be responsible for all or part of such costs to the extent that CERCLA imposes such responsibilities on such parties as “owners.”

The Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Drilling fluids, produced water and many other wastes associated with the exploration, development and production of oil or gas are currently excluded from regulation under RCRA’s hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes could be classified as hazardous wastes in the future. In addition, exploration and production wastes are regulated under state laws analogous to RCRA. Many of our properties have produced oil and/or gas for many years. We have no knowledge of current and prior operators’ procedures with respect to the disposal of oil and gas wastes. Hydrocarbons or other solid or hazardous wastes may have been released on or under our properties by the operators or prior operators. Our properties and the materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA and analogous state laws, and removal or remediation of such materials could be required by a governmental authority.

The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and other requirements, such as emissions controls. Existing laws and regulations and possible future laws and regulations may require our operators to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions and may impose stringent air permit requirements or use specific equipment or technologies to control emissions. The U.S. Environmental Protection Agency (“EPA”) continues to develop stringent regulations governing emissions of toxic air pollutants from oil and gas facilities. Specifically, on August 16, 2012, the EPA issued final regulations under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAPs”). These regulations are designed to reduce volatile organic compound (“VOC”) emissions from hydraulically fractured wells and other equipment. Under the regulations, since January 1, 2015 owners and operators of hydraulically fractured natural gas wells (wells drilled principally for the production of natural gas) have been required to use reduced emissions (“green”) completion technology to recover natural gas that formerly would have been flared or vented. On May 12, 2016, the EPA issued a suite of new final regulations designed to limit methane and VOC emissions. Among other things, these new rules apply green completion requirements to newly fractured and refractured oil wells. Obtaining permits and complying with these new requirements has the potential to increase costs of production and delay the development of our properties.

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In November 2016, the Bureau of Land Management ("BLM") published a final version of its venting and flaring rule, which imposes stricter reporting obligations and limits venting and flaring of natural gas on federal and Indian lands. Some provisions of the venting and flaring rule went into effect on January 17, 2017. The BLM has announced that it is postponing until January 17, 2019, the implementation of other aspects of the venting and flaring rule, which were originally scheduled to come into effect on January 1, 2018. And, on February 22, 2018, the BLM issued a proposed rule which would rescind, modify, and retain portions of the November 2016 rule. In March 2015, the BLM released its new regulations governing hydraulic fracturing operations on federal and Indian lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule and a final decision is pending. In December 2017, the BLM repealed the 2015 regulations, and environmental organizations and the State of California are suing the BLM and the Secretary of the U.S. Department of the Interior over the repeal. Each of these regulations, to the extent that they are reinstated or modified, may result in additional levels of regulation or complexity that could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase costs of compliance.

The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws impose restrictions and strict controls on the discharge of pollutants and fill material, including spills and leaks of oil and other substances into regulated waters, including wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, an analogous state agency, or, in the case of fill material, the United States Army Corps of Engineers. In May 2015, EPA and the U.S. Army Corps of Engineers jointly announced a final rule defining the "Waters of the United States, " which are protected under the Clean Water Act. The new rule, which would have made additional waters expressly Waters of the United States and, therefore, subject to the jurisdiction of the Clean Water Act, rather than subject to a case-specific evaluation, was stayed by the U.S. Court of Appeals for the Sixth Circuit before it took effect. On February 1, 2018, EPA officially delayed implementation of the 2015 rule until early 2020. Meanwhile, the U.S. Army Corps of Engineers and the EPA could initiate rulemaking to revise the definition of "Waters of the United States." Compliance with the Clean Water Act may restrict the location of certain facilities, require the mitigation of impacted wetlands, increase the cost of capital expenditures, and may result in permitting delays.

Spill prevention, control, and countermeasure ("SPCC") regulations promulgated under the Clean Water Act and later amended by the Oil Pollutions Act of 1990 impose obligations and liabilities related to the prevention of oil spills and damages resulting from such spills into or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities that store oil in more than threshold quantities, the release of which could reasonably be expected to reach jurisdictional waters, must develop, implement, and maintain SPCC Plans. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Safe Drinking Water Act ("SDWA") and the Underground Injection Control ("UIC") program require that permits be obtained before drilling salt water disposal wells, and casing integrity monitoring be conducted periodically to ensure that the disposed waters are not leaking into groundwater. In addition, because some states have become concerned that the injection or disposal of produced water could, under certain circumstances, trigger or contribute to seismic activity, they have adopted or are considering additional regulations regarding such disposal methods. Changes in regulations or the inability to obtain permits for new disposal wells in the future may affect the ability of the operators of the Royalty Properties and the operators of the working interests and other properties underlying our NPIs to dispose of produced water and ultimately increase the cost of operation of the Royalty Properties and the working interests and other properties underlying our NPIs or delay production schedules. For example, in 2014, the Railroad Commission of Texas ("RRC") published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the RRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds and their habitat, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the CWA, and CERCLA. The United States Fish and Wildlife Service ("USFWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of, or harm to, species or damages to wetlands, habitat or natural resources occur or may occur, government entities or at times private parties may act to restrict or prevent oil and gas exploration or production activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or production activities, including, for example, for releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and, in some cases, criminal penalties.

Operations of the Royalty Properties and the working interests and other properties underlying our NPIs may be subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes and their implementing regulations. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes may require disclosure of information about hazardous materials used, produced or otherwise managed during operation of the Royalty Properties and the working interests and other properties underlying our NPIs. These laws also require the development of risk management plans for certain facilities to prevent accidental releases of extremely hazardous substances and to minimize the consequences of such releases should they occur.

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The potential adoption of federal and state hydraulic fracturing legislation or executive orders could delay or restrict development of our oil and natural gas properties.

The Energy Policy Act of 2005 exempts hydraulic fracturing from federal regulation under the SDWA, provided that diesel fuel is not used in the fracturing process. In prior Congressional Sessions, legislation has been introduced that would have repealed this exemption. If similar legislation were enacted, it could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. Such federal legislation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing.

In 2010, the EPA asserted federal regulatory authority over hydraulic fracturing involving diesel additives through an informal policy statement posted on the agency's website. Industry groups filed a lawsuit challenging the EPA's decision. In February 2012, the EPA and industry reached a settlement under which the EPA agreed to issue hydraulic fracturing permitting guidance through the notice and comment process. The EPA published a draft guidance document in May 2012, and accepted comments through August 2012. In February 2014, the EPA published final guidance that broadly defined diesel fuel and which requires the issuance of a Class II Underground Injection Control permit for hydraulic fracturing treatments using diesel fuel. These requirements may cause additional costs and delays in the hydraulic fracturing process using diesel fuel.

The EPA has also asserted in certain cases involving alleged groundwater contamination that it has emergency authority under the SDWA to issue administrative compliance orders to require clean-up of groundwater. Although the United States Supreme Court has held that such orders are subject to pre-enforcement judicial review, the EPA maintains that it has the authority to continue to issue such orders.

The EPA's Office of Research and Development ("ORD") has conducted a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. The ORD published a report in 2016, concluding that hydraulic fracturing operations do impact drinking water resources under some circumstances but declining to reach conclusions about the frequency or severity of those impacts. In addition to the EPA study, there are other governmental reviews that focus on environmental aspects of hydraulic fracturing. In April 2012, President Obama issued an executive order establishing an interagency working group to coordinate Federal policies related to unconventional gas development. In addition, a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. These or other investigations, initiatives, and studies could result in additional efforts to regulate hydraulic fracturing.

Beyond studying hydraulic fracturing, certain members of Congress have called upon the Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources and asked the Securities and

Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing. Any new federal restrictions on hydraulic fracturing resulting from these efforts could result in delays, additional permitting and financial assurance requirements, and more stringent construction requirements, thereby significantly increasing operating, capital and compliance costs. Such cost increases could delay or restrict development by operators of our oil and natural gas properties.

Additionally, certain states in which our properties are located, including Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, pursuant to legislation adopted by the State of Texas in June 2011, the Railroad Commission of Texas enacted a rule in December 2011, requiring public disclosure of certain information regarding additives, chemical ingredients, concentrations and water volumes used in hydraulic fracturing. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit well drilling in general and/or hydraulic fracturing in particular. In response to a 2014 ballot initiative by the voters of the City of Denton, Texas banning hydraulic fracturing, the Texas legislature enacted a statute preempting local government regulation of oil and gas activities, including hydraulic fracturing. In other states, however, local governments may retain the ability to directly or indirectly regulate hydraulic fracturing. State and local governments may also seek to regulate or recover costs of activities tangentially associated with hydraulic fracturing, such as increased truck traffic. In the event state, local, or municipal legal restrictions are adopted in areas where our properties are located, the cost of the operators of our oil and natural gas properties complying with such requirements may be significant in nature, which may cause delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even preclude the operators from drilling wells.

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

Congress has, from time to time, considered legislation to reduce greenhouse gas (“GHG”) emissions. To date, Congress has not passed a bill specifically addressing GHG regulation. Almost half of the states, however, have developed GHG emission inventories and/or regional GHG cap and trade programs. These cap and trade programs require major sources of emissions or major fuel producers to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Many states also have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

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In December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment by contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA required the agency to adopt regulations to restrict GHG emissions under the Federal Clean Air Act. In 2010, the EPA issued a final rule "tailoring" its New Source Review permitting and Federal Operating Permit programs to apply to facilities with certain thresholds of GHG emissions. This "Tailoring Rule" was challenged in court, and on June 23, 2014, the United States Supreme Court struck down the Tailoring Rule in *Utility Air Regulatory Group v. Environmental Protection Agency*. In its decision, the Court held that the EPA may not impose permitting requirements on facilities based solely on their emissions of GHGs. But, the Court also held that the EPA may regulate GHG emissions if a facility is otherwise subject to permitting based on the emissions of conventional, non-GHG pollutants. Thus, any new facilities or major modifications to existing facilities that exceed the federal New Source Review emission thresholds for conventional pollutants may be required to use "best available control technology" and energy efficiency measures to minimize GHG emissions. In December 2010, the EPA enacted final regulations on mandatory reporting of GHGs. Those regulations required owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalent or CO2E) to annually report carbon dioxide, methane and nitrous oxide emissions, beginning in September 2012. The EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG emission limits.

Although it is not possible at this time to predict whether or when Congress may act on climate change legislation, or whether EPA may promulgate additional regulation of GHGs from the oil and gas industry, 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 the Royalty 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.

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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.

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.

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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, Bradley J. Ehrman, its Chief Operating Officer and Leslie A. Moriyama, its Chief Financial Officer. The loss of the services of any of these key personnel could have a material adverse effect on the results of our 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 generally do not obtain rulings or assurances from the IRS or state or local taxing authorities on matters affecting us.

We generally have not requested, and do not intend to request, rulings from the Internal Revenue Service, or IRS, or state or local taxing authorities with respect to owning and disposing of our common units or other matters affecting us. 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. Notwithstanding the foregoing, in 2013 we obtained a ruling from the IRS permitting us to aggregate the Minerals NPI and the Maecenas NPI for federal income tax purposes effective January 1, 2013.

Recently enacted U.S. tax legislation may adversely affect our business, results of operations and cash flow.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”) that makes significant changes to U.S. federal income tax laws. Among other changes, the Tax Act (i) introduces a new deduction on certain pass-through income, (ii) repeals the partnership technical termination rule and (iii) imposes a new limitation on the deductibility of interest expense. Many of the provisions in the Tax Act, including the deduction related to certain pass-through income, are temporary and, without additional legislation, will sunset on December 31, 2025. The Tax Act is complex and lacks administrative guidance, thus, the impact of certain aspects of its provisions on us or an investment in our common units is currently unclear. There may be other material adverse effects resulting from the Tax Act that we have not identified and that could have an adverse effect on our business, results of operations, financial conditions and cash flow.

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.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. A change in our business or a change in current law (including administrative guidance relating to the Tax Act) could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 21%. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Several states have subjected, or are evaluating ways to subject, partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders. Therefore, treatment of us as a corporation or the assessment of a material amount of entity-level taxation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for federal income tax purposes.

Additionally, on January 19, 2017, the IRS and the U.S. Department of the Treasury publicly released the text of final regulations (the "Final Regulations") regarding qualifying income under Section 7704(d)(1)(E) of the Code, which provide that income earned from a royalty interest is qualifying income. On January 24, 2017, the Final Regulations were published in the Federal Register. Under current law, we believe that our royalty income is qualifying income for purposes of Section 7704(d)(1)(E) of the Code. If the Final Regulations remain effective in their current form, we believe we will continue to be able to meet the qualifying income requirement under the new rules. However, there are no assurances that the Final Regulations will not be revised to take a position that is contrary to our interpretation of the current law.

While the Tax Act does not negatively impact the final regulations or the qualifying income exception, we are unable to predict whether any of these changes or any other proposals will ultimately be enacted or adopted, or whether final qualifying income regulations will materially change interpretations of the current law. Any such changes could negatively impact the value of an investment in our common units.

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. The U.S. Treasury Department has issued final Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferors and transferee unitholders. Nonetheless, 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.

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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. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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.

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.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We generally will have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so under all circumstances. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced.

Disclosure Regarding Forward-Looking Statements

Statements included in this report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "may," "believe," "will," "expect," "anticipate," "estimate," "continue" or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other forward-looking information.

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These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and, therefore, involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements for a number of important reasons, including those discussed under "Risk Factors" and elsewhere in this report.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Facilities

Our office in Dallas consists of 11,847 square feet of leased office space. The operating partnership owns a field office in Hooker, Oklahoma.

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, 2017, a summary of our gross and net acres, where applicable, 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	18	18	8	25
Number of Counties/Parishes	465	190	137	34	574
Gross Acres	2,313,000	624,000	209,000	33,000	3,125,000
Net Acres (where applicable)	379,000	—	—	—	379,000

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 previous 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.

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The following table sets forth, as of December 31, 2017, the combined summary of total gross and net acres, where applicable, of mineral, royalty, overriding royalty and leasehold interests in each of the states in which these interests are located.

State	**Gross(1)**	**Net(1)**	**State**	**Gross(1)**	**Net(1)**
Alabama	105,000	8,000	Missouri	<500	< 500
Arkansas	47,000	15,000	Montana	282,000	63,000
California	1,000	< 500	Nebraska	3,000	< 500
Colorado	23,000	1,000	New Mexico	42,000	3,000
Florida	89,000	25,000	New York	23,000	19,000
Georgia	4,000	1,000	North Dakota	292,000	46,000
Illinois	5,000	1,000	Oklahoma	230,000	17,000
Indiana	< 500	< 500	Pennsylvania	10,000	6,000
Kansas	14,000	2,000	South Dakota	14,000	1,000
Kentucky	2,000	1,000	Texas	1,646,000	154,000
Louisiana	132,000	3,000	Utah	6,000	< 500
Michigan	54,000	3,000	Wyoming	27,000	1,000
Mississippi	72,000	9,000			

(1) < 500 means acreage owned did not round up to 1,000.

Leasing Activity

We received $2,399,000 during 2017 attributable to lease bonus on 16 leases or extension of existing leases, and 1 pooling election in lands located in 11 counties and parishes in four states. These leases reflected bonus payments ranging up to $40,000/acre and initial royalty terms ranging up to 25%.

The following table sets forth a summary of leases and pooling elections consummated during 2015 through 2017.

	2017	**2016**	**2015**
Number	17	37	14
Number of States	4	7	4
Number of Counties	11	22	10
Average Royalty	23.94 %	24.92 %	24.8 %
Average Bonus, $/acre(1)	$3,330	$2,499	$305
Total Lease Bonus	$2,399,000	$2,721,000	$53,000

(1) Based on net acreage weighted average.

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 Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner. We refer to Dorchester Minerals Operating LP as the “operating partnership” or “DMOLP.” We receive monthly payments from each of the five NPIs equaling 96.97% of the net profits actually realized by the operating partnership from these properties in the preceding month. In the event costs, including budgeted capital expenditures, exceed revenues on a cash basis in a given month for properties subject to a Net Profits Interest, no payment is made and any deficit is accumulated and carried over and reflected in the following month's calculation of net profit. In the event an NPI has a deficit of cumulative revenue versus cumulative costs, the deficit will be borne solely by the operating partnership.

Minerals NPI production volumes and prices are within the consolidated financial statements in accordance with U.S. GAAP, although accrued net profits income for the year ended December 31, 2015 from the Minerals NPI was zero because accrued cumulative capital costs exceeded accrued cumulative operating income on a temporary deficit basis. The amount included in Net Profits Income for the Minerals NPI properties for the years ended December 31, 2016 and December 31, 2017 was $4.6 million and $6.5 million, respectively.

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From a cash perspective, as of December 31, 2017, the Minerals NPI was in a surplus position and had outstanding capital commitments equaling cash on hand of $6.6 million.

Acreage Summary

The following tables set forth, as of December 31, 2017, information concerning properties owned by the operating partnership and subject to the NPIs. 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	6	6	12
Number of Counties/Parishes	61	23	12	68
Gross Acres	50,000	—	91,000	141,000
Net Acres	6,000	—	75,000	81,000

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

	Mineral/Royalty		**Leasehold**		**Total**	
	Gross	**Net[(1)]**	**Gross**	**Net[(1)]**	**Gross**	**Net[(1)]**
Oklahoma	12,000	1,000	80,000	74,000	92,000	75,000
Arkansas	1,000	< 500	8,000	1,000	9,000	1,000
All Others	38,000	5,000	3,000	< 500	41,000	5,000
Totals	50,000	6,000	91,000	75,000	141,000	81,000

(1) < 500 means acreage owned did not round up to 1,000.

The leasehold acreage in Arkansas listed above includes all of the acreage in the Fayetteville Shale properties in which the operating partnership participates as a working interest owner.

Productive Well Summary

The following table sets forth, as of December 31, 2017, the approximate combined number of producing wells on the properties subject to the NPIs. Gross wells refer to wells in which a working interest is owned. Net wells are determined by multiplying gross wells by our working interest in those wells.

	Productive Wells/Units[1]	
Location	**Gross**	**Net**
Oklahoma	133	117
All others	800	30
Total	933	147

(1) Large, multi-well units which are forecasted in aggregate are included as one gross well.

Drilling Activity

During 2017, we received division orders or first payments for 409 new wells completed on our Royalty Properties and 52 new wells completed on our NPI Properties. The wells were located in 32 counties and parishes in seven states. Included in these totals are wells in which we own both a royalty interest and a net profits interest. Wells with such overlapping interests are counted in both categories.

We have and will continue to consider a range of transaction structures for our unleased mineral interests including leasing to third parties, working interest participation through the operating partnership, electing non-consent under State laws, or a combination thereof.

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Oil and Natural Gas Reserves

The following table reflects the Partnership's proved developed and total proved reserves at December 31, 2017. The reserves are based on the reports of two independent petroleum engineering consulting firms: Calhoun, Blair & Associates and LaRoche Petroleum Consultants, Ltd. 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 our filings with the SEC, we have not filed the estimated proved reserves with, or included them 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.

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 Chief Operating Officer (“COO”) gathers production information and provides such information to our two independent petroleum 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 COO. Our COO 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 COO reports directly to the Chief Executive Officer (“CEO”). Our CEO ensures compliance with SEC guidance. Our CEO 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.

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**	
Year	Oil(2) (mbbls)	Natural Gas (mmcf)	Oil(2) (mbbls)	Natural Gas (mmcf)	Oil(2) (mbbls)	Natural Gas (mmcf)
2017	6,688	24,327	1,623	22,594	8,311	46,921
2016	5,643	22,967	1,449	18,187	7,092	41,154
2015	4,631	23,618	1,047	25,752	5,678	49,370

(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) Oil reserves include volumes attributable to natural gas liquids.

Proved oil and natural gas reserves means those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and governmental regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Please see "Item 7 – 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 net sales volumes for the last three years are listed below:

	Production by Significant Field	
	Oil Boe[(1)]	**Gas mcf**
2017	47,000	1,388,000
2016	64,000	1,951,000
2015	—	2,066,000

(1) Oil revenues include volumes attributable to natural gas liquids.

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

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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 table summarizes the high and low sales information for the common units for the period indicated.

	2017		**2016**	
	High	**Low**	**High**	**Low**
First Quarter	$19.10	$15.50	$11.99	$8.57
Second Quarter	$17.85	$14.21	$15.82	$10.71
Third Quarter	$15.92	$13.90	$16.74	$13.55
Fourth Quarter	$15.66	$14.30	$19.30	$14.45

As of December 31, 2017, there were 12,346 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 three years have been:

	Per Unit Amount		
	2017	**2016**	**2015**
First Quarter	$0.306700	$0.147417	$0.306553
Second Quarter	$0.322965	$0.257977	$0.167430
Third Quarter	$0.284650	$0.252224	$0.194234
Fourth Quarter	$0.386915	$0.241475	$0.199076

Distributions were paid on 30,675,431 units from the first quarter of 2015 through the first quarter of 2017. Beginning with the second quarter of 2017, distributions were paid on 32,279,774 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, 2018.

Please see "Fourth Quarter 2017 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 cash receipts and weighted average prices corresponding to the fourth quarter 2017 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, 2012 through December 31, 2017. 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 on the last trading day of each quarter. 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 have been publicly traded on the New York Stock Exchange for the entire comparison period. Our peer group index includes the units of the following companies: Cross Timbers Royalty Trust, Mesa Royalty Trust, Sabine Royalty Trust, Permian Basin Royalty Trust, Hugoton Royalty Trust and the San Juan Basin Royalty Trust.

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ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Units Purchased		(b) Average Price Paid per Unit	(c) Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Units that May Yet Be Purchased Under the Plans or Programs	
Month #1 (October 1, 2017 – October 31, 2017)	-		N/A	-	83,249	(1)
Month #2 (November 1, 2017 – November 30, 2017)	8,197	(2)	15.00	8,197	83,249	(1)
Month #3 (December 1, 2017 – December 31, 2017)	-		-	-	83,249	(1)
Total	8,197	(2)	15.00	8,197	83,249	(1)

(1) The number of common units that the operating partnership may grant under the Dorchester Minerals Operating LP Equity Incentive Program, which was approved by our common unitholders on May 20, 2015 (the "**Equity Incentive Program**"), each fiscal year may not exceed 0.333% of the number of common units outstanding at the beginning of the fiscal year. In 2017, the maximum number of common units that could be purchased under the Equity Incentive Program was 102,149 common units.

(2) Common units withheld from grants of common units made pursuant to the Equity Incentive Program to pay withholding taxes payable by the grantee upon such grants.

ITEM 6. SELECTED 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)				
	2017	**2016**	**2015**	**2014**	**2013**
Total operating revenues	$57,291	$37,557	$31,870	$65,170	$65,869
Depreciation, depletion and amortization	9,302	8,507	10,068	10,050	13,143
Net income	38,424	20,967	13,255	45,239	43,576
Net income per common unit (basic and diluted)	1.18	0.66	0.42	1.42	1.37
Cash distributions[1]	37,797	27,202	36,608	60,539	55,015
Cash distributions per unit[1]	1.16	0.86	1.15	1.90	1.73
Total assets	92,047	67,211	73,729	97,509	112,785
Total liabilities	1,301	275	558	985	961
Partnership capital	90,746	66,936	73,171	96,524	111,824

(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

2017 Overview

Our results during 2017 were mainly affected by industrywide increases in realized oil and natural gas prices and continued drilling activity in the Permian Basin. Significant results include the following:

Net income of $38.4 million;