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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, 2003**

**Or**

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from __________ to __________**

**Commission file number: 000-50175**

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

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

**3738 Oak Lawn Avenue, Suite 300**
**Dallas, Texas 75219**
**(Address of principal executive offices) (Zip Code)**

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

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

| Title of Each Class | Name of Exchange on which Registered |
|---|---|
| None | Not applicable |

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

**Title of Class**

Common Units Representing Limited Partnership Interests

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

Indicate by check mark whether the registrant is an accelerated filer (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 $371,704,595 as of June 30, 2003, based on $17.57 per unit, the closing price of the common units as reported on the NASDAQ National Market on such date.

Number of Common Units outstanding as of March 8, 2004: 27,040,431

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the definitive proxy statement for the registrant's 2004 Annual Meeting of Unitholders to be held on May 5, 2004, 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, 2003.

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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 National Market. Our executive offices are located at 3738 Oak Lawn Avenue, Suite 300, Dallas, Texas, 75219-4379 and our telephone number is (214) 559-0300. In this report, the term "Partnership", as well as the terms "us," "our," "we," and "its," are sometimes used as abbreviated references to Dorchester Minerals, L.P. itself or Dorchester Minerals, L.P. and its related entities.

Our general partner is Dorchester Minerals Management LP, which is managed by its general partner, Dorchester Minerals Management GP LLC. As a result, the Board of Managers of Dorchester Minerals Management GP LLC exercises effective control of our Partnership. In this report, the term "general partner" is used as an abbreviated reference to Dorchester Minerals Management LP. Our general partner also controls and owns, directly and indirectly, all of the partnership interests in Dorchester Minerals Operating LP and its general partner, Dorchester Minerals Operating GP LLC. Dorchester Minerals Operating LP owns the working interest and other properties underlying our Net Profits Interests, provides day-to-day operational and administrative services to us and our general partner and is the employer of all of 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 partner of our general partner and Dorchester Minerals Operating GP LLC are Delaware limited liability companies. These entities and our Partnership were initially formed in December 2001 in connection with the combination that occurred on January 31, 2003.

Our business may be described as the acquisition, ownership and administration of Net Profits Interests and Royalty Properties. The Net Profits Interests represent net profits overriding royalty interests burdening various properties owned by the operating partnership. These properties include working interests formerly owned by Dorchester Hugoton and various mineral and working interest properties formerly owned by Republic and Spinnaker. We receive monthly payments equaling 96.97% of the net profits actually realized by the operating partnership from these properties in the preceding month. The Royalty Properties consist of producing and non-producing mineral, royalty, overriding royalty, net profits and leasehold interests formerly owned by Republic and Spinnaker located in 563 counties and parishes in 25 states.

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

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

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

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

We also intend to grow by encouraging exploration and development of our unleased mineral interests through our relationship with the operating partnership.

**Basis of Presentation**

Prior to January 31, 2003 we had no operations. The combination transaction consummated on that date among Dorchester Hugoton, Republic and Spinnaker was treated as a purchase by Dorchester Hugoton for accounting purposes. **In these circumstances, the financial condition, portions of the business and properties information, and the results of operations are required to be presented for the deemed accounting acquiror, Dorchester Hugoton, for all years ended on or before December 31, 2002. Our Partnership's financial condition, portions of the business and properties information and the results of operations for the twelve-month period ended December 31, 2003 are required to consist of the one-month period ended January 31, 2003 for Dorchester Hugoton and the eleven-month period ended December 31, 2003 for our Partnership. For the purposes of this presentation, the term combination means the transactions consummated in connection with the combination of the business and properties of Dorchester Hugoton, Republic and Spinnaker.**

**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 percent 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.

**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:

- requiring permits for the drilling of wells;

- maintaining bonding requirements in order to drill or operate wells;
- regulating the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandonment of wells;
- 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 regulate the size of drilling and spacing units or proration units and the density of wells which 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 limit the amount of oil and natural gas that the operators of our properties can produce and limit the number of wells or the locations at which the operators can drill.

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

**Customers and Pricing**

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

The operating partnership sells most of its natural gas to Williams Power Company, Inc. on a month-to-month basis. The Williams Companies, Inc. has announced that it intends to reduce its commitment to Williams Power, either through the sale of all or a portion of its assets or by entering into a joint venture with a third party. The operating partnership is reviewing alternative gas purchasers which may result in less favorable pricing and payment terms, which could affect the Net Profits Interests payments to us. We believe that the loss of Williams Power by the operating partnership or the loss of any single customer would not have a material adverse effect on the results of our operations.

**Acquisitions**

On January 31, 2003, Dorchester Hugoton contributed assets to us and the operating partnership and then liquidated. Republic and Spinnaker contributed their working interest properties to the operating partnership and then merged with us. As a result, the operating partnership owns certain working interests and management assets and we own the Net Profits Interests and the Royalty Properties.

**Competition**

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

### Operating Hazards and Uninsured Risks

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

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

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

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

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

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

### Employees

As of February 29, 2004, the operating partnership had 15 full-time employees in our Dallas and Garland, Texas offices and nine full-time employees in field locations.

## ITEM 2. PROPERTIES

### Facilities

The operating partnership leases 13,420 square feet of office space in Dallas and Garland, Texas for our Partnership offices. The operating partnership also owns a field office in Hooker, Oklahoma and leases part of an office in Amarillo, Texas under a month-to-month lease. The operating partnership anticipates combining the Dallas and Garland offices into one location during 2004.

### Properties

Our Partnership owns two categories of properties, the Net Profits Interests and the Royalty Properties.

***Net Profits Interests***

The Net Profits Interests represent net profits overriding royalty interests burdening various properties owned by the operating partnership. These properties include working interests formerly owned by Dorchester Hugoton and various mineral and working interest properties formerly owned by Republic and Spinnaker. We receive monthly payments equaling 96.97% of the net profits actually realized by the operating partnership from these properties in the preceding month. The information set forth below with respect to the Net Profits Interests does not include information prior to 2003 attributable to the properties formerly owned by Republic and Spinnaker. We believe that the exclusion of this information is immaterial.

*Acreage*

The following tables set forth as of December 31, 2003 information concerning properties owned by the operating partnership and subject to the Net Profits Interests. Acreage amounts listed under Leasehold reflect gross acres leased by the operating partnership and the working interest share 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 in those properties. The operating partnership's interest in these properties may be unleased, leased by others or a combination thereof. All Mineral acreage is considered to be developed although additional drilling activity may occur on those properties. Acreage amounts may not add across due to overlapping ownership among categories.

| | Mineral | | | | |
|---|---|---|---|---|---|
| | Leased | Unleased | Royalty | Leasehold | Total |
| Number of States | 5 | 8 | 1 | 4 | 9 |
| Number of Counties/Parishes | 12 | 28 | 1 | 4 | 33 |
| Gross Acres | 5,250 | 31,015 | 640 | 81,816 | 124,080 |
| Net Acres (where applicable) | 611 | 3,073 | — | 81,162 | 84,847 |

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

| | Leasehold | | Mineral/Royalty | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Oklahoma | 79,861 | 74,031 | 6,882 | 383 | 86,743 | 74,414 |
| Kansas | 7,035 | 7,035 | 640 | 20 | 7,675 | 7,055 |
| All Others | 920 | 95 | 28,742 | 3,283 | 29,662 | 3,378 |
| Totals | 87,816 | 81,161 | 36,264 | 3,686 | 124,080 | 84,847 |

In addition to the Leasehold acres listed above, the operating partnership owns working interests below the currently producing horizons in 47,360 gross/46,960 net acres in Texas County, Oklahoma. The operating partnership has from time to time farmed out its interests in portions of these lands, reserving an overriding royalty interest therein, and will consider additional exploration or development of these lands as circumstances warrant.

*Costs Incurred and Drilling Results*

During 2003, the operating partnership participated as a working interest or unleased mineral interest owner in 35 wells located on lands subject to the Net Profits Interests. These wells are located in 10 counties and parishes in four states. As of December 31, 2003, 26 of these wells had been completed as producing oil or natural gas wells, three were deemed to be dry holes and six were in various stages of drilling or completion operations.

The following table sets forth information regarding 100% of the costs incurred in acquisition and development activities during the periods indicated in connection with the properties underlying the Net Profits Interests.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | | (in thousands) | |
| Acquisition costs (1) | $ 3 | $148 | $5,297 |
| Development costs (2) | 1,393 | 21 | 240 |
| Total | $1,396 | $169 | $5,537 |

(1) The year ended December 31, 2001 includes $5,270,000 paid for an Oklahoma production payment.
(2) The year ended December 31, 2003 includes $336,000 not yet deducted from the Net Profits Interests payments.

*Productive Well Summary*

The following table sets forth as of December 31, 2003 the combined number of producing wells on the properties subject to the Net Profits Interests. Gross wells refer to wells in which a working interest is owned. Net wells are determined by multiplying gross wells by the working interest in those wells.

| | Productive Wells/Units(1) | |
|---|---|---|
| Location | Gross | Net |
| Oklahoma | 144 | 115.5 |
| Kansas | 20 | 20.0 |
| All others | 83 | 6.1 |
| Total | 247 | 141.6 |

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

See “Management’s Discussion and Analysis of Financial Condition and Results of Operations–Basis of Presentation” for a discussion of average costs and prices for the Net Profits Interests.

***Royalty Properties***

The Royalty Properties represent producing and nonproducing mineral, royalty, overriding royalty net profits and leasehold interests in properties located in 563 counties and parishes in 25 states. Acreage amounts listed herein represent our best estimates based on information provided to us as a royalty owner. However, due to the significant number of individual deeds, leases and similar instruments involved in the acquisition and development of the Royalty Properties by Republic, Spinnaker and their 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 leases and other contracts pursuant to which we are not entitled to well information. Some of our 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 at any point in time 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.

We received cash payments in the amount of $542,190 from various sources during 2003, including lease bonus attributable to 42 leases and forced pooling elections of our interests in lands located in 31 counties and parishes in eight states. These leases reflected bonus payments ranging up to $350/acre and initial royalty terms ranging from 15% to 28.5%. These cash payments are reflected in our financial statements in various categories including, but not limited to, lease bonus, other operating revenue, investment income, and other income.

We received cash payments in the amount of $183,884 from various sources during the fourth quarter of 2003, including lease bonus attributable to eight leases and forced pooling elections of our interests in lands located in eight counties and parishes in six states. These leases reflected bonus payments ranging up to $350/acre and royalty terms ranging from 19% to 27.5%, with one lease reflecting a royalty term of 25% escalating to 30% after payout. These cash payments are reflected in our financial statements in various categories including, but not limited to, lease bonus, other operating revenue, investment income, and other income.

We identified 198 new wells completed on our properties in 57 counties and parishes in 10 states during 2003. We identified 35 new wells completed on our properties in 18 counties and parishes in seven states during the fourth quarter of 2003. New wells identified during the fourth quarter of 2003 included the Chesapeake Operating Buffalo Creek 1-17 well located in Beckham County, Oklahoma which tested at a rate of 3,520 mcf of gas per day and in which we own an approximate 1.2% net revenue interest; and the CrownQuest Operating Keystone Cattle Co. #443 well located in Winkler County, Texas which tested at rates of 243 barrels of oil and 175 mcf of gas per day and in which we own an approximate 1.1% net revenue interest.

*Acreage Summary*

The following table sets forth as of December 31, 2003 a summary of our gross and net, where applicable, acres of mineral, royalty, overriding royalty and leasehold interests, and a compilation of the number of counties and parishes and states and the development status of the acres in each category. Acreage amounts may not add across due to overlapping ownership among categories.

| | Mineral | | | | | |
|---|---|---|---|---|---|---|
| | Leased | Unleased | Royalty | Overriding Royalty | Leasehold | Total |
| Number of States | 19 | 25 | 17 | 18 | 8 | 25 |
| Number of Counties/Parishes | 207 | 423 | 190 | 140 | 35 | 563 |
| Gross | 600,150 | 1,523,138 | 551,876 | 228,683 | 35,398 | 2,939,245 |
| Net (where applicable) | 69,974 | 268,652 | — | — | — | 338,626 |

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. For example, our net interest in production from properties in which we own a royalty or overriding royalty interest will be affected by royalty terms negotiated by the mineral interest owners in such tracts and their lessees. Our interest in the majority of these properties is perpetual in nature. However, a portion of the properties are subject to terms and conditions pursuant to which all or a portion of our interest may be forfeited or otherwise terminated.

The following table sets forth as of December 31, 2003 the combined summary of total gross and net (where applicable) acres of mineral, royalty, overriding royalty and leasehold interests in each of the states in which these interests are located.

| State | Gross | Net | State | Gross | Net |
|---|---|---|---|---|---|
| Alabama | 106,074 | 7,797 | Missouri | 334 | 43 |
| Arkansas | 47,551 | 15,453 | Montana | 285,232 | 62,850 |
| California | 924 | 162 | Nebraska | 3,360 | 257 |
| Colorado | 22,880 | 1,424 | New Mexico | 32,947 | 2,002 |
| Florida | 88,832 | 24,249 | New York | 23,077 | 18,440 |
| Georgia | 3,676 | 1,024 | North Dakota | 293,774 | 37,202 |
| Illinois | 4,480 | 761 | Oklahoma | 205,697 | 14,810 |
| Indiana | 303 | 113 | Pennsylvania | 9,511 | 4,653 |
| Kansas | 9,074 | 1,334 | South Dakota | 14,408 | 1,266 |
| Kentucky | 1,995 | 553 | Texas | 1,511,539 | 130,119 |
| Louisiana | 112,657 | 1,677 | Utah | 5,937 | 200 |
| Michigan | 54,367 | 2,623 | Wyoming | 28,448 | 1,137 |
| Mississippi | 72,156 | 8,477 | | | |

*Activity Summary*

The following table sets forth a summary of leases consummated and new wells added during 1999 through 2003 giving effect to the combination and assuming the consummation of the combination on January 1 of each year.

| | 2003 | 2002 | 2001 | 2000 | 1999 |
|---|---|---|---|---|---|
| Consummated Leases | | | | | |
| Number | 27 | 25 | 17 | 47 | 26 |
| Number of States | 8 | 4 | 5 | 6 | 6 |
| Number of Counties | 20 | 14 | 14 | 25 | 21 |
| Average Royalty | 23.2% | 24.2% | 23.7% | 24.8% | 24.9% |
| Average Bonus, $/acre | $ 96 | $ 49 | $ 272 | $ 150 | $ 192 |
| Total Lease Bonus | $251,996 | $ 29,976 | $173,217 | $ 436,627 | $ 744,938 |
| Other Land Revenue | 374,297 | 454,797 | 330,714 | 2,260,342 | 558,981 |
| Total Land Revenue | $626,293 | $484,773 | $503,931 | $2,696,969 | $1,303,919 |
| New Wells Added | | | | | |
| Number | 198 | 176 | 212 | 124 | 150 |
| Number of States | 10 | 7 | 11 | 8 | 8 |
| Number of Counties | 57 | 38 | 64 | 49 | 50 |

In addition to the activity set forth in the foregoing table, we made 15 elections during 2003 to lease under Oklahoma Corporation Commission pooling orders which generally do not provide for the payment of lease bonus. The number of new producing wells completed on the Royalty Properties each year generally reflects our best estimate of new exploratory activity and does not include many wells drilled on oil leases or in units subsequent to their initial discovery or development. For example, more than 250 completions were reported to the Texas Railroad Commission during 2001, 2002 and 2003 attributable to various oil producing units located in Andrews, Gaines and Yoakum Counties, Texas in which we own royalty interests. None of these wells are included in the "New Wells Added" category.

Other Land Revenue includes gas storage, shut-in and delay rental payments, surface use agreements, litigation judgments and settlement proceeds, proceeds of royalty payment audits and other sources. These cash payments are reflected in our financial statements in various categories including, but not limited to, lease bonus, other operating revenue, investment income, and other income.

**Oil and Natural Gas Reserves**

The following table sets forth on a pro forma basis proved developed and total proved reserves, future net revenues and SEC PV-10 at December 31, 2002 giving effect to the combination on January 31, 2003 as if it occurred on December 31, 2002. The table also shows the same actual information at December 31, 2003. The reserves and revenues are based on the reports of Calhoun, Blair & Associates as to the Net Profits Interests properties and Huddleston & Co., Inc. as to the Royalty Properties, both independent petroleum engineer consulting firms. Other than those filed with the SEC, our estimated proved reserves have not been filed with or included in any reports to any federal agency.

| | 2003 (Actual) | | | 2002 (Pro Forma) | | |
|---|---|---|---|---|---|---|
| | Net Profits Interest(1) | Royalty Properties | Total | Net Profits Interest(1) | Royalty Properties | Total |
| Proved reserves | | | | | | |
| Natural gas (mmcf)(2) | 41,773 | 28,354 | 70,127 | 42,200 | 30,935 | 73,135 |
| Oil (mbbls)(3) | 47 | 3,722 | 3,769 | — | 4,061 | 4,061 |
| Future net revenues ($, in thousands)(4) | $ 156,496 | $ 252,464 | $ 408,960 | $ 124,821 | $ 243,950 | $ 368,771 |
| SEC PV-10 (4) ($, in thousands) | $ 105,478 | $ 128,345 | $ 233,823 | $ 86,991 | $ 124,525 | $ 211,516 |

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

(2) Total proved reserves include 582 mmcf and 1,285 mmcf of proved undeveloped gas reserves attributable to the Royalty Properties at December 31, 2003 and 2002, respectively.

(3) Total proved reserves include 2 mbbls and 1 mbbl of proved undeveloped oil reserves attributable to the Royalty Properties at December 31, 2003 and 2002, respectively.

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

**Title to Properties**

Our general partner believes we have satisfactory title to all of our assets. Record title to essentially all our assets has undergone the appropriate filings in the jurisdictions in which such assets are located. Title to property may be subject to encumbrances. Our general partner believes that none of such encumbrances should materially detract from the value of our properties or from our interest in these properties or should materially interfere with their use in the operation of our business.

## ITEM 3. LEGAL PROCEEDINGS

In connection with the combination, we succeeded to the rights and liabilities of Dorchester Hugoton, Republic and Spinnaker with respect to all legal proceedings involving those partnerships.

In January 2002, some individuals and an association called Rural Residents for Natural Gas Rights, referred to as RRNGR, sued Dorchester Hugoton, Ltd., Anadarko Petroleum Corporation, Conoco, Inc., XTO Energy Inc., ExxonMobil Corporation, Phillips Petroleum Company, Incorporated and Texaco Exploration and Production, Inc. The operating partnership, owned directly and indirectly by our general partner, now owns and operates the properties formerly owned by Dorchester Hugoton. These properties contribute a major portion of the Net Profits Interests amounts paid to our Partnership. The suit is currently pending in the District Court of Texas County, Oklahoma and discovery is underway by the plaintiffs and defendants. The individuals and RRNGR consist primarily of Texas County, Oklahoma residents who, in residences located on leases, use natural gas from gas wells located on the same leases, at their own risk, free of cost. The plaintiffs seek declaration that their domestic gas use is not limited to stoves and inside lights and is not limited to a principal dwelling as provided in the oil and gas lease agreements with defendants in the 1930s to the 1950s. Plaintiffs' claims against defendants include failure to prudently operate wells, violation of rights to free domestic gas, violation of irrigation gas contracts, underpayment of royalties, a request for an accounting, and fraud. Plaintiffs also seek certification of class action against defendants. The operating partnership believes plaintiffs' claims are completely without merit. In July 2002, the defendants were granted a motion for summary judgment removing RRNGR as a plaintiff. Based upon past measurements of such gas usage, the operating partnership believes the damages sought by plaintiffs to be minimal. An adverse decision could reduce amounts our Partnership receives from the Net Profits Interests.

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

## ITEM 4. SUBMISSION OF A MATTER TO A VOTE OF UNITHOLDERS

No matters were submitted to a vote of unitholders during the fourth quarter of the year ended December 31, 2003.

# PART II.

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED UNITHOLDER MATTERS

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

| | 2003 | |
|---|---|---|
| | **High** | **Low** |
| First Quarter (starting February 3, 2003) | $ 17.000 | $ 12.550 |
| Second Quarter | $ 19.539 | $ 14.250 |
| Third Quarter | $ 18.400 | $ 16.700 |
| Fourth Quarter | $ 20.050 | $ 16.390 |

As of December 31, 2003, there were 5,088 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 generally 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 law or agreements or obligations to which we may be subject. Due to the timing of our receipt of production revenues, our initial quarterly distribution generally reflected two months of production from the Royalty Properties and one month of production from the properties underlying the Net Profits Interests, rather than three months production from both. This was a one-time occurrence associated with the creation of the Net Profits Interests and the delay in our receipt of revenue, as well as the January 31, 2003 closing date of the combination. In addition, our initial quarterly distribution also reflected payment of costs and expenses for which we are responsible in connection with the combination, such as NASDAQ listing fees, director and officer insurance premiums, recording and filing fees and legal expenses. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Distributions."

**Recent Sales of Unregistered Securities**

In connection with the closing of the combination on January 31, 2003, under the terms of the combination agreement we issued (i) a number of common units determined in accordance with the combination agreement to Dorchester Hugoton which were distributed to the former general partners of Dorchester Hugoton as part of the liquidation of Dorchester Hugoton and (ii) general partner interests in our Partnership to the former general partners of Republic and Spinnaker. The former general partners of Dorchester Hugoton, Republic and Spinnaker contributed the common units and general partner interests, as applicable, to our general partner in accordance with the terms of the Contribution Agreement dated December 13, 2001. Under the terms of our partnership agreement, the common units contributed to our general partner by the former general partners of Dorchester Hugoton were converted into general partner interests in our Partnership. The foregoing transactions were exempt from registration under the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof on the basis that the transactions did not involve a public offering. No underwriters were involved in the foregoing transactions. Other than the foregoing transactions, there have been no other sales of unregistered securities by our Partnership during the last three years.

**ITEM 6. SELECTED FINANCIAL DATA**

The combination of Republic, Spinnaker and Dorchester Hugoton on January 31, 2003 was accounted for as a purchase and Dorchester Hugoton was designated as the accounting acquirer in connection with the combination. Prior to January 31, 2003, our Partnership had no combined operations. **As a result, the following table sets forth a summary of historical selected financial and operating data for Dorchester Hugoton for 1999 through 2002, and certain pro forma operating data assuming the combination occurred on January 1, 2002. As required, the data presented for fiscal year ended December 31, 2003 consists of 11 months of our Partnership's results and January 2003 results for Dorchester Hugoton.** This table should be read in conjunction with the financial statements and related notes included elsewhere in this document. All of the historical data presented prior to 2003 has been derived from the audited financial statements of Dorchester Hugoton and does not contain any information with respect to Republic or Spinnaker, or our Partnership, pre-combination.

| | Fiscal Year Ended December 31, (in thousands, except per unit data) | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2003 | 2002 | 2001 | 2000 | 1999 |
| | Pro Forma | | Historical | | | | |
| Total operating revenues | $ 51,113 | $37,547 | $ 49,224 | $18,738 | $26,779 | $25,182 | $15,302 |
| Depreciation, depletion and amortization | $ 25,390 | $25,844 | $ 23,639 | $ 2,130 | $ 2,105 | $ 1,783 | $ 1,903 |
| Impairment | $ 43,804 | — | $ 43,804 | — | — | — | — |
| Net earnings (loss) | $(26,976) | $ 6,524 | $ (26,827) | $12,963 | $18,351 | $17,962 | $ 9,046 |
| Net earnings (loss) per unit | $ (0.97) | $ 0.24 | $ (1.02) | $ 1.19 | $ 1.69 | $ 1.66 | $ 0.83 |
| Cash distributions (1) | | | $ 50,798 | $ 8,791 | $13,349 | $ 9,768 | $ 7,814 |
| Cash distributions per unit (1) | | | $ 1.94 | $ 0.81 | $ 1.23 | $ 0.90 | $ 0.72 |
| Total assets | | | $198,951 | $40,103 | $41,454 | $38,709 | $28,165 |
| Long-term debt, including current portion | | | — | — | — | $ 100 | $ 100 |
| Total liabilities | | | $ 512 | $ 1,233 | $ 4,118 | $ 5,779 | $ 3,827 |
| Partners' equity | | | $198,439 | $38,870 | $37,336 | $32,930 | $24,338 |

(1) Because of depletion (which is usually higher in the early years of production), a portion of every distribution of revenues from properties represents a return of a limited partner's original investment. Until a limited partner receives cash distributions equal to his original investment, in certain circumstances, 100% of such distributions may be deemed to be a return of capital. Cash distributions for 2003 exclude the fourth quarter distribution declared in January 2004 and paid in February 2004. Cash distributions for 2003 include Dorchester Hugoton's liquidating distribution declared in January 2003.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### Basis of Presentation

In the combination completed on January 31, 2003 and accounted for as a purchase, Dorchester Hugoton was designated as the accounting acquirer. Prior to January 31, 2003, our Partnership had no combined operations. In these circumstances, we are required to present, discuss and analyze the financial condition and results of operations of Dorchester Hugoton, the accounting acquiror, for the two years ended December 31, 2002 and the financial condition and results of operations of our Partnership for the year ended December 31, 2003, which includes the results of operations for Dorchester Hugoton for the one month period ended January 31, 2003 and the financial condition and results of operations for our Partnership for the eleven month period ended December 31, 2003. For the purposes of this presentation, the term combination means the transactions consummated in connection with the combination of the business and properties of Dorchester Hugoton, Republic and Spinnaker.

Normally, our period-to-period changes in net earnings and cash flows from operating activities are principally determined by changes in oil and natural gas sales volumes and prices, and to a lesser extent, by capital expenditures deducted under the Net Profits Interests calculation. Our portion of gas and oil sales volumes and weighted average sales prices were:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Sales Volumes: | | | |
| Dorchester Hugoton Gas Sales (mmcf) (1) | 448 | 5,540 | 5,930 |
| Net Profits Interests Gas Sales (mmcf) | 5,001 | — | — |
| Net Profits Interests Oil Sales (mbbls) | 7 | — | — |
| Royalty Properties Gas Sales (mmcf) | 3,288 | — | — |
| Royalty Properties Oil Sales (mbbls) | 297 | — | — |
| Weighted Average Sales Price: | | | |
| Dorchester Hugoton Gas Sales ($/mcf) | $ 5.20 | $ 3.26 | $ 4.44 |
| Net Profits Interests Gas Sales ($/mcf) | $ 5.36 | — | — |
| Net Profits Interests Oil Sales ($/bbl) | $ 28.74 | — | — |
| Royalty Properties Gas Sales ($/mcf) | $ 5.11 | — | — |
| Royalty Properties Oil Sales ($/bbl) | $ 28.63 | — | — |
| Production Costs Deducted Under the Net Profits Interests ($/mcfe) (2) | $ 1.17 | $ 0.95 | $ 0.87 |

(1) For purposes of comparison both the January 2003 and all 2002 and 2001 Dorchester Hugoton volumes have been reduced to reflect our 96.97% Net Profits Interests in production from the underlying properties.

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

### Results of Operations

***Year Ended December 31, 2003 Compared with the Year Ended December 31, 2002***

Natural gas sales volumes attributable to the former Dorchester Hugoton properties underlying our Net Profits Interests declined 4.8% from 5,540 mmcf during 2002 to 5,272 mmcf during 2003. Such declines result from natural reservoir depletion partially offset by added gas compression. See "—Liquidity and Capital Resources—Expenses and Capital Expenditures."

Oil and natural gas sales volumes attributable to the Royalty Properties and oil and natural gas sales volumes attributable to the Net Profits Interests in properties formerly owned by Republic and Spinnaker prior to

February 2003 are not included in the table above. See "—Basis of Presentation" and Note 1 of the Notes to Financial Statements.

The weighted average sales price for natural gas production from the former Dorchester Hugoton properties underlying our Net Profits Interests increased 65% from $3.26 per mcf during the year 2002 to $5.37 per mcf during the year 2003 as a result of changing market conditions.

Weighted average oil and natural gas sales prices attributable to the Royalty Properties and oil and natural gas sales prices attributable to the Net Profits Interests in properties formerly owned by Republic and Spinnaker prior to February 2003 are not included in the table above. See "—Basis of Presentation" and Note 1 of the Notes to Financial Statements.

Our 2003 net operating revenues increased 162.7% from $18,738,000 during 2002 to $49,224,000 primarily as a result of increased natural gas prices combined with the effects of the combination. Management cautions the reader in the comparison of results for these periods because revenues attributable to properties formerly owned by Republic and Spinnaker are not included in the periods prior to February 2003. See "—Basis of Presentation" and Note 1 of the Notes to Financial Statements.

During 2003, several categories of costs were higher than in 2002 as a result of non-recurring expenses associated with the 2003 liquidation of Dorchester Hugoton. Such comparisons include combination and related expenses which increased from $736,000 to $3,080,000 primarily as a result of approximately $2,500,000 in severance payments and related costs. Similarly, management fees in 2003 include a one-time $496,000 charge. Also, general and administrative costs including tax and regulatory expenses increased from $921,000 to $2,988,000 primarily as a result of $445,000 in insurance premiums for Dorchester Hugoton officers and directors continuation coverage and the costs of office facilities and personnel resulting from the combination with Republic and Spinnaker. See "—Basis of Presentation" and Note 1 of the Notes to Financial Statements.

Depletion, depreciation and amortization increased from $2,130,000 in 2002 to $23,639,000 in 2003 primarily as a result of the effects of a higher depreciable base due to effects of purchase accounting rules required for the combination. Cash flow from operations and cash distributions to unitholders are not affected by depletion, depreciation and amortization. Management cautions the reader in the comparison of results for these periods because operations of the properties formerly owned by Republic and Spinnaker are not included in the periods prior to February 2003. See "—Basis of Presentation," and Note 1 of the Notes to Financial Statements.

During 2003, our Partnership recorded non-cash charges against earnings totaling $43,804,000. The write-down represents an impairment of oil and gas properties that resulted primarily from the difference, after accumulated depletion and prior write-downs, between the discounted present value of our Partnership's proved natural gas and oil reserves using the quarter ending gas and oil prices as compared to the initial book value assigned to former Republic and Spinnaker assets in accordance with purchase accounting rules, which value significantly exceeded historic book value. The write-down is a function of such increased initial book value, accumulated depletion and prior write-downs, and changes in prevailing oil and gas prices since the combination transaction. Cash flow from operations and cash distributions to unitholders are not affected by the write-down. See Notes 1 and 6 of the Notes to Financial Statements and "—Liquidity and Capital Resources—Critical Accounting Policies."

Considering the impairment (asset write-down) representing the non-cash charge to earnings, 2003 net earnings decreased from $12,963,000 during 2002 to a loss of $26,827,000. Earnings excluding the asset write-down, (a financial measure not defined by generally accepted accounting principles) increased 31.0% from $12,963,000 during 2002 to $16,977,000 during 2003 due primarily to increased oil and natural gas prices and the effects of the combination. Earnings excluding the asset write-down are computed in accordance with generally accepted accounting principles with the exception of the exclusion of the asset write-down. Management believes the presentation of earnings excluding the asset write-down is useful to unitholders because energy industry investors generally see disclosure of earnings before impairment charges and because it is consistent with industry practice.

Management cautions the reader in the comparison of results for these periods. The operations of the properties formerly owned by Republic and Spinnaker are not included for the periods prior to February 2003 because of purchase accounting rules. See "—Basis of Presentation" and Notes 1 and 6 of the Notes to Financial Statements and "—Liquidity and Capital Resources—Critical Accounting Policies."

Net cash provided by operating activities increased 216% from $12,174,000 during 2002 to $38,522,000 during 2003 due primarily to the effects of the combination as well as increased natural gas prices compared to the same periods of 2002. Management cautions the reader in the comparison of results for these periods because operations of the properties formerly owned by Republic and Spinnaker are not included for the periods prior to February 2003. See "—Basis of Presentation" and Note 1 of the Notes to Financial Statements.

***Year Ended December 31, 2002 Compared with the Year Ended December 31, 2001***

See "—Basis of Presentation" and Note 1 to the Notes to Financial Statements.

As shown in the table on page 12, Dorchester Hugoton's gas sales volumes during 2002 were 6.6% lower than in 2001. Dorchester Hugoton's Oklahoma volumes were influenced by reduced gas pipeline receipts in 2002 because of an explosion unrelated to Dorchester Hugoton and natural reservoir decline. Dorchester Hugoton's Kansas gas sales volumes during 2002 were lower than in 2001 as a result of state well testing and natural reservoir decline.

Dorchester Hugoton's natural gas weighted average sales prices in 2002 declined 27% from 2001. The significantly lower gas prices and lower gas volumes caused net operating revenues to decrease in 2002 compared to 2001.

Dorchester Hugoton's operating costs during 2002 were lower than in 2001 primarily as a result of lower production taxes associated with reduced gas revenues and lower operating expenses as a result of the completion in 2001 of scheduled Oklahoma engine maintenance repairs of approximately $300,000.

Dorchester Hugoton recognized a gain in other income of $2,000,000 on the sale of ExxonMobil stock during December 2002, which was sold in anticipation of the combination.

In summary, net income declined in 2002 as compared to 2001 primarily as a result of the significant decline in natural gas prices in 2002 as compared to 2001.

## Liquidity and Capital Resources

***Capital Resources***

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

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

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

***Expenses and Capital Expenditures***

The operating partnership does not currently anticipate drilling additional wells as a working interest owner in the Fort Riley zone or the Council Grove formations or elsewhere in the Oklahoma properties previously owned by Dorchester Hugoton. Successful activities by others in these formations could prompt a reevaluation of this position. Any such drilling is estimated to cost $250,000 to $300,000 per well. The operating partnership anticipates continuing additional fracture treating in the Oklahoma properties previously owned by Dorchester Hugoton but is unable to predict the cost until additional engineering studies are performed. Previous fracture treatments in those properties have cost between $36,000 and $45,000 per well, excluding any needed casing repairs. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests.

The operating partnership owns and operates the wells, pipelines and gas compression and dehydration facilities located in Kansas and Oklahoma previously owned by Dorchester Hugoton. The operating partnership anticipates gradual increases in expenses as repairs to these facilities become more frequent, and anticipates gradual increases in field operating expenses as reservoir pressure declines. The operating partnership does not anticipate incurring significant expense to replace these facilities at this time. The operating partnership incurred approximately $767,000 of capital costs in connection with the installation of field compression facilities on portions of its Oklahoma properties during the second and third quarters of 2003. Incremental operating costs (primarily compressor rentals) attributable to these facilities are estimated to be approximately $680,000 per year. These capital and operating costs are reflected in the Net Profit Interests payments we receive from the operating partnership. Gas sales from the operating partnership's Oklahoma properties previously owned by Dorchester Hugoton during the second half of 2003 were approximately 12% greater than during the first half of 2003. Reserves assigned to these properties at December 31, 2003 were approximately 10% greater than at December 31, 2002. Management believes the increased gas sales and reserves are largely due to the installation of additional field compression capacity. The operating partnership does not currently plan to install additional field compression capacity.

In 1998, Oklahoma regulations removed production quantity restrictions in the Guymon-Hugoton field, and did not address efforts by third parties to persuade Oklahoma to permit infill drilling in the Guymon-Hugoton field. Both infill drilling and removal of production limits could require considerable capital expenditures. The outcome and the cost of such activities are unpredictable. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests. No additional compression affecting the wells formerly owned by Dorchester Hugoton has been installed since 2000 by operators on adjoining acreage. The operating partnership believes it now has sufficient field compression to remain competitive with adjoining operators for the foreseeable future.

***Liquidity and Working Capital***

Year-end cash and cash equivalents totaled $10,881,000 for 2003, $23,129,000 for 2002, and $18,439,000 for 2001.

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***Distributions***

Distributions to limited partners and general partners related to cash receipts for the period from February through December 2003 were as follows:

| 2003 Quarter | Record Date | Payment Date | Per Unit Amount | Limited Partners | General Partners |
|---|---|---|---|---|---|
| 1st (partial) | April 28, 2003 | May 8, 2003 | $ 0.206469 | $ 5,583,012 | $ 169,679 |
| 2nd | July 28, 2003 | August 7, 2003 | $ 0.458087 | 12,386,870 | 319,359 |
| 3rd | October 31, 2003 | November 10, 2003 | $ 0.422674 | 11,429,286 | 296,944 |
| Total distributions paid in 2003 | | | | $ 29,399,168 | $ 785,982 |
| 4th | January 26, 2004 | February 5, 2004 | $ 0.391066 | 10,574,593 | 277,298 |
| Total distributions paid or declared related to cash receipts for the period February through December 2003 | | | | $ 39,973,761 | $ 1,063,280 |

In general, the limited partners are allocated 99% of the Net Profits Interest Receipts and 96% of the Royalty Properties Net Receipts.

*Net Profits Interests*

We receive monthly payments from the operating partnership equal to 96.97% of the net proceeds actually realized by the operating partnership from the properties underlying the Net Profits Interests. The operating partnership retains the 3.03% balance of these net proceeds. Net proceeds generally reflect gross proceeds attributable to oil and natural gas production actually received during the month less production costs actually paid during the same month. Production costs generally reflect drilling, completion, operating and general and administrative costs and exclude depletion, amortization and other non-cash costs. The operating partnership made Net Profits Interests Payments to us totaling $14,047,000 during March through September 2003, which payments reflected 96.97% of total net proceeds of $14,486,000 realized from February through August 2003. Net proceeds realized by the operating partnership during September through November 2003 were reflected in Net Profits Interests payments made during October through December 2003. These payments were included in the fourth quarter distribution paid in early 2004 and are excluded from this 2003 analysis.

*Royalty Properties*

Revenues from the Royalty Properties are typically paid to us with proportionate severance (production) taxes deducted and remitted by others. Additionally, we generally only pay ad valorem taxes, general and administrative costs, and marketing and associated costs since royalties and lease bonuses generally do not otherwise bear operating or similar costs. After deduction of the above described costs, our net cash receipts from the Royalty Properties during the period February through September 2003 were $16,138,000: $15,492,000 (96%) of which was distributed to the limited partners and $646,000 (4%) of which was distributed to the general partner. Proceeds received by us from the Royalty Properties during the period October through December 2003 became part of the distribution paid in 2004. Such distribution is excluded from this 2003 analysis.

*Distribution Determinations*

The actual calculation of distributions is performed each calendar quarter in accordance with our partnership agreement and the following calculation covering the period February through September 2003 demonstrates the method.

| | $ in Thousands | |
|---|---|---|
| | Limited Partners | General Partners |
| 1% of Net Profits Interests Paid to our Partnership | — | $ 140 |
| 99% of Net Profits Interests Paid to our Partnership | $13,907 | — |
| 4% of Net Cash Receipts from Royalty Properties | — | 646 |
| 96% of Net Cash Receipts from Royalty Properties | 15,492 | — |
| Total Distributions | $29,399 | 786 |
| Operating Partnership Share (3.03% of Net Proceeds) | — | 439 |
| Total General Partner Share | — | $ 1,225 |
| % of Total | 96% | 4% |

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

During the period February through September 2003, our Partnership's quarterly distribution payments to limited partners were based on all of its available cash. Our Partnership's only significant cash reserves that influenced quarterly payments were for ad valorem taxes. Additionally, certain production costs under the Net Profits Interests calculation and a small portion of management expense reimbursements include amounts for which funds were set aside monthly to enable payment when due. Examples are pension contributions and insurance premiums. These amounts generally are not held for periods over one year.

***General and Administrative Costs***

In accordance with our partnership agreement, we bear all general and administrative and other overhead expenses subject to certain limitations. We reimburse our general partner for certain allocable costs, including rent, wages, salaries and employee benefit plans. This reimbursement is limited to an amount equal to the sum of 5% of our distributions plus certain costs previously paid. Through December 31, 2003, the limitation was substantially in excess of the reimbursement amounts actually paid or accrued.

**Unaudited Pro Forma Data**

The following table sets forth summary unaudited pro forma financial data for our Partnership for the years ended December 31, 2003 and 2002 as though the combination occurred as of January 1, 2002. The pro forma amounts are not necessarily indicative of the results that may be reported in the future. Pro forma adjustments have been made to depletion, depreciation, and amortization to reflect the new basis of accounting for the assets of Spinnaker and Republic as of January 31, 2003, and to revenues to reflect the revenues of Dorchester Hugoton as Net Profits Interests.

| | Year ended December 31, | |
|---|---|---|
| | 2003 | 2002 |
| | (in thousands except per unit data) | |
| Statement of Operations Data: | | |
| Total operating revenues | $ 51,113 | $37,547 |
| Operating expenses, excluding depreciation, depletion and amortization | $ 9,203 | $ 5,179 |
| Depreciation, depletion and amortization | $ 25,390 | $25,844 |
| Impairment | $ 43,804 | — |
| Total operating expenses | $ 78,397 | $31,023 |
| Other income | $ 308 | — |
| Net earnings (loss) | $(26,976) | $ 6,524 |
| Net earnings (loss) per unit | $ (0.97) | $ 0.24 |

**Critical Accounting Policies**

We utilize the full cost method of accounting for costs related to our oil and gas properties. Under this method, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. In accordance with applicable accounting rules, Dorchester Hugoton was deemed to be the accounting acquirer of the Republic and Spinnaker assets. Our Partnership's acquisition of these assets was recorded at a value based on the closing price of Dorchester Hugoton's common units immediately prior to consummation of the combination transaction, subject to certain adjustments. Consequently, the acquisition of these assets was recorded at values that exceed the historical book value of these assets prior to consummation of the combination transaction. Our Partnership did not assign any book or market value to unproved properties, including nonproducing royalty, mineral and leasehold interests. The full cost ceiling is evaluated at the end of each quarter. For 2003, our unamortized costs of oil and gas properties exceeded the ceiling test. As a result, in 2003, our Partnership recorded full cost write-downs of $43,804,000.

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

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

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

**New Accounting Standards**

In July 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. Dorchester Minerals adopted SFAS No. 143 on January 1, 2003 which did not have a material effect on its financial statements.

We have been made aware that an issue has arisen within the industry regarding the application of provisions of Statement of Financial Accounting Standards No. 141, "Business Combinations," and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires companies to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, we and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties. Also under consideration is whether SFAS No. 142 requires companies to provide the additional disclosures prescribed by SFAS No. 142 for intangible assets for costs associated with mineral rights. A majority of the Partnership's oil and gas properties are perpetual in nature, so the applicability of SFAS 142 to these type of assets is not known at this time.

If it is ultimately determined that SFAS No. 142 requires us to reclassify costs associated with mineral rights from property and equipment to intangible assets, the amounts that would be reclassified would be immaterial to our financial position. The reclassification of these amounts would not affect the method in which such costs are amortized or the manner in which we assess impairment of capitalized costs. As a result, our cash flows and results of operations would not be affected by this reclassification.

**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 in significant part 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 to agree to and maintain oil prices and production controls;
- political instability or armed conflict in oil-producing regions;

- the price and level of foreign imports;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- weather conditions;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

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

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

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

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

Essentially all of the producing properties we acquired from Republic and Spinnaker are royalty interests. As a royalty owner, we do not control the development of these properties or the volumes of oil and natural gas produced from them. The decision to 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.

As the owner of a fractional undivided mineral or royalty interest, our ability to influence development of these nonproducing properties is severely limited. Also, since one of our stated business objectives is to avoid the generation of unrelated business taxable income, we will generally avoid participation in the development of our properties as a working interest or other expense-bearing owner. The decision to explore for oil and natural gas on these properties will be made by the operator and other working interest owners of each property (including our lessees) and may be influenced by factors beyond our control, including but not limited to oil and natural gas prices, interest rates, budgetary considerations and general industry and economic conditions.

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

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

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

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

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

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

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

The cash available for distribution that comes from our royalty and mineral interests, including the Net Profits Interests, is directly affected by increases in production costs and other costs. Some of these costs are outside 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. Our producing oil and natural gas properties over time will all experience declines in production due to depletion of their oil and natural gas reservoirs, with the rates of decline varying by property. Replacement of reserves to maintain production levels requires maintenance, development or exploration projects on existing properties, or the acquisition of additional properties.

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

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

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

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

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

- pressure or irregularities in formations;
- equipment failures or accidents;
- disputes with drill site landowners;
- 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 Net Profits Interests, the costs of unsuccessful future drilling on the working interest properties that are subject to the Net Profits Interests will reduce amounts payable to us under the Net Profits Interests by 96.97% of these costs.

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

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

Our partnership agreement obligates our general partner to use all reasonable efforts to avoid generating unrelated business taxable income. Accordingly, to acquire working interests we would have to arrange for them to be converted into overriding royalty interests or another type of interest that did not generate unrelated business taxable income in a manner similar to the treatment of Dorchester Hugoton's properties in the combination. 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, including pursuant to the terms of the Amended and Restated Business Opportunities Agreement. Accordingly, business opportunities that could potentially be pursued by us might not necessarily come to our attention, which could limit our ability to pursue a business strategy of acquiring oil and natural gas properties.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Some of the operating partnership's current working interest wells were drilled and have been producing since prior to 1954. The 132-mile Oklahoma gas pipeline gathering system acquired from Dorchester Hugoton 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 previously owned by Dorchester Hugoton prior to the consummation of the combination, which, as production costs, would reduce our cash flow from these properties.

*Our operations are 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 of these risks, either because such insurance is not available or because of high premium costs. Operations that affect the properties are subject to all of the risks normally incident to the oil and natural gas business, including blowouts, cratering, explosions and pollution and other environmental damage, any of which could result in substantial decreases in the cash flow from our overriding royalty interests and other interests due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Any uninsured costs relating to the properties underlying the Net Profits Interests will be deducted as a production cost in calculating the net proceeds payable to us.

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

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

As another example, Oklahoma regulations currently restrict the concentration of gas production wells to one well for each 640 acres. For some time, certain interested parties have sought regulatory changes in Oklahoma which would permit "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 permit infill drilling, it is possible that a number of producers will commence increased density drilling in areas adjacent to the properties in Oklahoma that are subject to the Net Profits Interests. If the operating partnership, or other operators of our properties do not do the same, our production levels relating to these properties may decrease. Capital expenditures relating to increased density on the properties underlying the Net Profits Interests would be deducted from amounts payable to us under the Net Profits Interests.

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

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

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

Estimates of proved reserves and related future net revenues are projections based on engineering data and reports of independent consulting petroleum engineers hired for that purpose. The process of estimating reserves requires substantial judgment, resulting in imprecise determinations. Different reserve engineers may make different estimates of reserve quantities and related revenue based on the same data. Therefore, those estimates should not be construed as being accurate estimates of the current market value of our proved reserves. If these estimates prove to be inaccurate, our business may be adversely affected by lower revenues. We are affected by changes in oil and natural gas prices. Oil prices and natural gas prices may not experience corresponding 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 accordance with generally accepted accounting practices. 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 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. Beginning with the 2004 annual meeting of limited partners, our unitholders only have the right to annually elect the managers comprising the Advisory Committee of the Board of Managers of the general partner of our general partner. Our unitholders do not have the right to elect the other managers of the general partner of our general partner, on an annual or any other basis.

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

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

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

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

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

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

*We may issue additional securities, diluting our unitholders' interests.*

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

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

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

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

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

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

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

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

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

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

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

**Disclosure Regarding Forward-Looking Statements**

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

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.

Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these 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 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 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

**Quantitative and Qualitative Disclosures About Market Risk**

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

***Market Risk Related to Oil and Natural Gas Prices***

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

***Absence of Interest Rate and Currency Exchange Rate Risk***

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

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

### ITEM 9A. CONTROLS AND PROCEDURES

**Evaluation of Disclosure Controls and Procedures**

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

**Changes in Internal Controls**

There were no changes in our Partnership's internal controls or in other factors that have materially affected, or are reasonably likely to materially affect, our Partnership's internal controls subsequent to the date of their evaluation of our disclosure controls and procedures.

## PART III

### ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item is incorporated herein by reference to the 2004 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2003.

### ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the 2004 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2003.

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

The information required by this item is incorporated herein by reference to the 2004 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2003.

### ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item is incorporated herein by reference to the 2004 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2003.

### ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item is incorporated herein by reference to the 2004 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2003.

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## PART IV

**ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K**

(a) Financial Statements and Schedules

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

| Number | Description |
|---|---|
| 3.1 | Certificate of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.1 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282) |
| 3.2 | Amended and Restated Agreement of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.2 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.3 | Certificate of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282) |
| 3.4 | Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.5 | Certificate of Formation of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.7 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282) |
| 3.6 | Amended and Restated Limited Liability Company Agreement of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.6 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.7 | Certificate of Formation of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282) |
| 3.8 | Limited Liability Company Agreement of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282) |
| 3.9 | Certificate of Limited Partnership of Dorchester Minerals Operating LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282) |
| 3.10 | Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Operating LP (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.11 | Certificate of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 3.12 | Agreement of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |

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| Number | Description |
|---|---|
| 3.13 | Certificate of Incorporation of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.13 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002.) |
| 3.14 | Bylaws of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.14 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 10.1 | Amended and Restated Business Opportunities Agreement dated as of December 13, 2001 by and between the Registrant, the General Partner, Dorchester Minerals Management GP LLC, SAM Partners, Ltd., Vaughn Petroleum, Ltd., Smith Allen Oil & Gas, Inc., P.A. Peak, Inc., James E. Raley, Inc., and certain other parties . (incorporated by reference to Exhibit 10.1 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 10.2 | Transfer Restriction Agreement (incorporated by reference to Exhibit 10.2 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002.) |
| 10.3 | Registration Rights Agreement (incorporated by reference to Exhibit 10.3 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 10.4 | Lock-Up Agreement by William Casey McManemin (incorporated by reference to Exhibit 10.4 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002) |
| 10.5 | Form of Lock-Up Agreement (incorporated by reference to Exhibit 10.5 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282) |
| 21.1* | Subsidiaries of the Registrant |
| 31.1* | Certification of Chief Executive Officer of our Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934 |
| 31.2* | Certification of Chief Financial Officer of our Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934 |
| 32.1* | Certification of Chief Executive Officer of our Partnership pursuant to 18 U.S.C. Sec. 1350 |
| 32.2* | Certification of Chief Financial Officer of our Partnership pursuant to 18 U.S.C. Sec. 1350 |

* Filed herewith

(b) Reports on Form 8-K during the quarter ended December 31, 2003 and through the date hereof.

(1) Filed October 16, 2003
(2) Filed November 7, 2003
(3) Filed January 16, 2004
(4) Filed March 5, 2004

## GLOSSARY OF CERTAIN OIL AND GAS TERMS

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

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

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

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

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

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

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

"*Gross acre*" means an acre in which a working interest is owned.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*Standardized measure of discounted future net cash flows"* (also referred to as *"standardized measure")* means the SEC PV-10 defined above, less applicable income taxes, if applicable.

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

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

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

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**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DORCHESTER MINERALS, L.P.

By: Dorchester Minerals Management LP,
its general partner

By: Dorchester Minerals Management GP LLC,
its general partner

By: /s/ William Casey McManemin

William Casey McManemin
Chief Executive Officer

Date: March 8, 2004

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

/s/ William Casey McManemin

William Casey McManemin
Chief Executive Officer and Manager
(Principal Executive Officer)
Date: March 8, 2004

/s/ H.C. Allen, Jr.

H.C. Allen, Jr.
Chief Financial Officer and Manager
(Principal Financial and Accounting Officer)
Date: March 8, 2004

/s/ James E. Raley

James E. Raley
Chief Operating Officer and Manager
Date: March 8, 2004

/s/ Preston A Peak

Preston A. Peak
Manager
Date: March 8, 2004

/s/ Robert C. Vaughn

Robert C. Vaughn
Manager
Date: March 8, 2004

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

## INDEX TO FINANCIAL STATEMENTS

Dorchester Minerals, L.P.

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## REPORT OF INDEPENDENT CERTIFIED ACCOUNTANTS

To the General Partners and Unitholders of Dorchester Minerals, L.P.:

We have audited the accompanying balance sheets of Dorchester Minerals, L.P. as of December 31, 2003 and 2002, and the related statements of operations, changes in partnership capital, and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above, present fairly, in all material respects, the financial position of Dorchester Minerals, L.P. as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON, LLP
Grant Thornton, LLP

Dallas, Texas
February 24, 2004

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

**BALANCE SHEETS**
**December 31, 2003 and 2002**
**(Dollars in Thousands)**

| | 2003 | 2002 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 10,881 | $ 23,129 |
| Trade receivables | 7,658 | 2,566 |
| Note receivable-related party | 205 | — |
| Prepaid expenses and other current assets | 69 | 223 |
| Total current assets | 18,813 | 25,918 |
| Property and equipment—at cost : | | |
| Oil and natural gas properties (full cost method) | 268,189 | 34,179 |
| Other | — | 1,001 |
| Total | 268,189 | 35,180 |
| Less accumulated depreciation, depletion and amortization : | | |
| Full cost depletion | 88,051 | 20,614 |
| Other | — | 381 |
| Total | 88,051 | 20,995 |
| Net property and equipment | 180,138 | 14,185 |
| Total assets | $ 198,951 | $ 40,103 |
| **LIABILITIES AND PARTNERSHIP CAPITAL** | | |
| Current liabilities: | | |
| Accounts payable and other current liabilities | $ 512 | $ 451 |
| Production and property taxes payable or accrued | — | 358 |
| Royalties payable | — | 423 |
| Distributions payable to Unitholders | — | 1 |
| Total current liabilities | 512 | 1,233 |
| Commitments and contingencies | — | — |
| Partnership capital: | | |
| General partner | 8,246 | 312 |
| Unitholders | 190,193 | 38,558 |
| Total partnership capital | 198,439 | 38,870 |
| Total liabilities and partnership capital | $ 198,951 | $ 40,103 |

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

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

**STATEMENTS OF OPERATIONS**
**For the Years Ended December 31, 2003, 2002 and 2001**
**(Dollars in Thousands)**

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Net operating revenues: | | | |
| Net profits interest | $ 21,268 | $ — | $ — |
| Natural gas sales | 2,401 | 18,602 | 27,153 |
| Royalties | 25,250 | — | — |
| Lease bonus | 293 | — | — |
| Other | 12 | 136 | 192 |
| Production payment (ORRI) | — | — | (566) |
| Total net operating revenues | 49,224 | 18,738 | 26,779 |
| Costs and expenses: | | | |
| Production taxes | 1,211 | 1,009 | 1,721 |
| Operating expenses | 1,113 | 2,806 | 3,160 |
| Depreciation, depletion and amortization | 23,639 | 2,130 | 2,105 |
| Impairment of full cost properties | 43,804 | — | — |
| Tax and regulatory expenses | 587 | 243 | 345 |
| General and administrative expenses | 2,401 | 678 | 634 |
| Management fees | 524 | 524 | 605 |
| Combination costs and related expenses | 3,080 | 736 | 785 |
| Total costs and expenses | 76,359 | 8,126 | 9,355 |
| Operating income (loss) | (27,135) | 10,612 | 17,424 |
| Other income (expense): | | | |
| Investment income | 125 | 2,385 | 897 |
| Interest expense | — | (15) | (36) |
| Other income (expense), net | 183 | (19) | 66 |
| Total other income (expense) | 308 | 2,351 | 927 |
| Net earnings (loss) | $ (26,827) | $ 12,963 | $ 18,351 |
| Allocation of net earnings (loss): | | | |
| General Partner | $ (641) | $ 130 | $ 184 |
| Unitholders | $ (26,186) | $ 12,833 | $ 18,167 |
| Net earnings (loss) per common unit (in dollars) | $ (1.02) | $ 1.19 | $ 1.69 |
| Weighted average common units outstanding (000's) | 25,682 | 10,744 | 10,744 |

**STATEMENTS OF COMPREHENSIVE INCOME (LOSS)**
**For the Years Ended December 31, 2003, 2002 and 2001**
**(Dollars in Thousands)**

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Net earnings (loss) | $ (26,827) | $ 12,963 | $ 18,351 |
| Unrealized loss on available for sale securities | — | (513) | (534) |
| Reclassification adjustment for gains included in net earnings | — | (2,000) | — |
| Comprehensive income (loss) | $ (26,827) | $ 10,450 | $ 17,817 |

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

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

**STATEMENTS OF CASH FLOWS**
**For the Years Ended December 31, 2003, 2002 and 2001**
**(Dollars in Thousands)**

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net earnings (loss) | $ (26,827) | $ 12,963 | $ 18,351 |
| Adjustments to reconcile net earnings to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 23,639 | 2,130 | 2,105 |
| Impairment of full cost properties | 43,804 | — | — |
| Gain on sale of available-for-sale securities | — | (2,000) | — |
| Loss (gain) on sale of assets | (55) | 25 | (22) |
| Other | — | (125) | (62) |
| Changes in operating assets and liabilities net of effect of combination: | | | |
| Restricted cash | — | — | 409 |
| Receivables | (1,908) | (1,094) | 2,620 |
| Prepaid expenses | 61 | 230 | (169) |
| Accounts payable, taxes and royalties payable | (192) | 45 | (2,203) |
| Net cash provided by operating activities | 38,522 | 12,174 | 21,029 |
| Cash flows from investing activities: | | | |
| Cash received in combination | 68 | — | — |
| Capital expenditures | (40) | (321) | (5,587) |
| Cash received on sale of ExxonMobil stock | — | 4,517 | — |
| Cash received on sale of property and equipment | — | 41 | 37 |
| Net cash provided by (used in) investing activities | 28 | 4,237 | (5,550) |
| Cash flows from financing activities: | | | |
| Distributions paid to partners | (50,798) | (11,721) | (12,807) |
| Increase (decrease) in cash and cash equivalents | (12,248) | 4,690 | 2,672 |
| Cash and cash equivalents at beginning of year | 23,129 | 18,439 | 15,767 |
| Cash and cash equivalents at end of year | $ 10,881 | $ 23,129 | $ 18,439 |
| Noncash investing and financing activities: | | | |
| Acquisition of assets for units | | | |
| Oil and gas properties | $ 233,466 | $ — | $ — |
| Receivables | 3,660 | — | — |
| Cash | 68 | — | — |
| Value assigned to assets acquired | $ 237,194 | $ — | $ — |
| Supplemental cash flow and other information: | | | |
| Interest paid (no interest was capitalized) | $ — | $ 22 | $ 28 |
| Distributions declared but not paid | $ — | $ 1 | $ 2,931 |

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

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

**STATEMENTS OF CHANGES IN PARTNERSHIP CAPITAL**
**For the Years Ended December 31, 2003, 2002 and 2001**
**(Dollars in Thousands)**

| Year | General Partners | Unitholders | Accumulated Other Comprehensive Income | Total |
|---|---|---|---|---|
| 2001 | | | | |
| Balance at January 1, 2001 | $ 222 | $ 29,661 | $ 3,047 | $ 32,930 |
| Net earnings | 183 | 18,168 | — | 18,351 |
| Net unrealized holding loss on investments available for sale | — | — | (534) | (534) |
| Distributions ($1.23 per Unit) | (133) | (13,216) | — | (13,349) |
| Other | (1) | (61) | — | (62) |
| Balance at December 31, 2001 | 271 | 34,552 | 2,513 | 37,336 |
| 2002 | | | | |
| Net earnings | 130 | 12,833 | — | 12,963 |
| Net unrealized holding loss on investments available for sale | — | — | (513) | (513) |
| Reclassification adjustment for gains included in net earnings | — | — | (2,000) | (2,000) |
| Distributions ($0.81 per Unit) | (88) | (8,703) | — | (8,791) |
| Other | (1) | (124) | — | (125) |
| Balance at December 31, 2002 | 312 | 38,558 | — | 38,870 |
| 2003 | | | | |
| Net loss – January | (17) | (1,725) | — | (1,742) |
| Liquidating distribution to Dorchester Hugoton, Ltd. Partners ($1.90 per Unit) | (199) | (20,414) | — | (20,613) |
| Acquisition of assets for units | 9,560 | 227,634 | — | 237,194 |
| Net loss – February through December | (624) | (24,461) | — | (25,085) |
| Distributions ($1.08723 per Unit) | (786) | (29,399) | — | (30,185) |
| Balance at December 31, 2003 | $ 8,246 | $ 190,193 | $ — | $ 198,439 |

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

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

**NOTES TO FINANCIAL STATEMENTS**
**December 31, 2003, 2002 and 2001**

**1. General and Summary of Significant Accounting Policies**

*Nature of Operations*—In these Notes, the term “Partnership,” as well as the terms “us,” “our,” “we,” and “its” are sometimes used as abbreviated references to Dorchester Minerals, L.P. itself or Dorchester Minerals, L.P. and its related entities. Our Partnership is a Dallas, Texas based owner of producing and non-producing natural gas and crude oil royalty, net profits, and leasehold interests in 563 counties and 25 states. Dorchester Hugoton, Ltd.’s operations consisted principally of the operation of natural gas properties located in Kansas and Oklahoma.

*Basis of Presentation*—Our Partnership is a publicly traded Delaware limited partnership that was formed in December 2001 in connection with the combination, which was completed on January 31, 2003, of Dorchester Hugoton, Ltd., (Dorchester Hugoton) which was a publicly traded Texas limited partnership, and Republic Royalty Company (Republic) and Spinnaker Royalty Company, L.P. (Spinnaker), both of which were privately held Texas partnerships.

The accompanying financial statements reflect the combination completed on January 31, 2003 and accounted for using the purchase method of accounting. See Note 2. In accordance with the purchase method of accounting, Dorchester Hugoton was designated as the accounting acquirer. Under the purchase method of accounting, our Partnership used the market price of Dorchester Hugoton’s partnership units on January 31, 2003, adjusted for the liquidating distribution to Dorchester Hugoton unitholders, to determine the value of the Republic and Spinnaker oil and gas properties merged into our Partnership. Such method increased the historic book values of the oil and gas properties of Republic and Spinnaker by approximately $192,000,000 which increased our Partnership’s depletion.

Our Partnership is required to present the financial statements of Dorchester Hugoton, the accounting acquirer, for 2001 and 2002 and the financial statements of our Partnership for the twelve month period ended December 31, 2003, which includes the results of operations for Dorchester Hugoton for the one month period ended January 31, 2003 and the financial condition and results of operations for our Partnership for the eleven month period ended December 31, 2003.

Per-unit information is calculated by dividing the earnings or loss applicable to holders of our Partnership’s common units by the weighted average number of units outstanding. Per-unit information for Dorchester Hugoton during 2002 and 2001 is calculated by dividing the 99% interest owned by Dorchester Hugoton unitholders by the 10,744,380 units outstanding.

*Reclassification*—Certain amounts in the 2002 and 2001 financial statements have been reclassified to conform to the 2003 presentation.

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

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

*Cash and Cash Equivalents*—Our principal banking is with major financial institutions. Cash balances in these accounts may, at times, exceed federally insured limits. We have not experienced any losses in such cash accounts and do not believe we are exposed to any significant risk on cash and cash equivalents.

*Concentration of Credit Risks*—Our Partnership, as a royalty owner, has no control over the volumes or method of sale of oil and natural gas produced and sold from the royalty properties. It is believed that the loss of any single customer would not have a material adverse effect on the results of our operations. Dorchester Hugoton has incurred only minimal credit losses.

*Trade Receivables*—Our Partnership's trade receivables consist primarily of royalties receivable and net profits interest payments receivable. Most payments are received two to four months after production date. No allowance for doubtful accounts is deemed necessary.

*Note Receivable–Related Party*—Our Note Receivable consists of a five-year note payable by Dorchester Minerals Operating LP, referred to in these Notes as "the operating partnership," bearing interest at 6% having an original amount of $250,836. Principal and interest payments are received quarterly.

*Property and Equipment*—We (and Dorchester Hugoton) utilize the full cost method of accounting for costs related to our oil and gas properties. Under this method, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. In accordance with applicable accounting rules, Dorchester Hugoton was deemed to be the accounting acquirer of the Republic and Spinnaker assets. Our Partnership's acquisition of these assets was recorded at a value based on the closing price of Dorchester Hugoton's common units immediately prior to consummation of the combination transaction, subject to certain adjustments. Consequently, the acquisition of these assets was recorded at values that exceed the historical book value of these assets prior to consummation of the combination transaction. Our Partnership did not assign any value to unproved properties, including nonproducing royalty, mineral and leasehold interests. The full cost ceiling is evaluated at the end of each quarter. For the second and third quarters of 2003, our unamortized costs of oil and gas properties exceeded the ceiling test. During 2003, our Partnership has recorded such full cost write-downs of $43,804,000.

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

Our Partnership's properties are being depleted on the unit-of-production method using such estimates of proved gas reserves. Gains and losses are recognized upon the disposition of oil and gas properties involving a significant portion of our Partnership's reserves. Proceeds from other dispositions of oil and gas properties are credited to the full cost account.

*General Partner*—Our general partner is Dorchester Minerals Management LP, referred to in these Notes as "our general partner." Our general partner owns all of the partnership interests in Dorchester Minerals Operating LP, the operating partnership. See Note 3. The general partner is allocated 1% and 4% of our net profits interests and royalty properties revenues, respectively. Our executive officers all own an interest in our general partner and receive no compensation for services as officers of our Partnership.

Dorchester Hugoton's two General Partners had the overall responsibility for the management, operation and future development of the properties. Each General Partner was entitled to receive reasonable compensation in the form of management fee, to be divided among the General Partners in an annual aggregate amount of $350,000 plus 1% of the gross income for services rendered in operating and managing Dorchester Hugoton. The General Partners were also reimbursed for all general and administrative expenses incurred by them on behalf of Dorchester Hugoton.

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

Revenues from royalty interests and net profits interests are recorded under the cash receipts approach as directly received from the remitters' statement, accompanying the revenue check. Since the revenue checks are generally received two to four months after the production month, the Partnership accrues for revenue earned but not received.

Dorchester Hugoton's purchasers who accounted for more than 10% of natural gas revenues for each of the years ended December 31, 2002, and 2001 are as follows:

| Year | Purchaser "A" | Purchaser "B" |
|---|---|---|
| 2002 | 84% | N/A |
| 2001 | 83% | 16% |

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

*Simplified Employee Pension Plan*—Contributions aggregating $273,267, $165,949, and $150,980 were made to eligible employees' accounts for 2003, 2002 and 2001, respectively, under Dorchester Hugoton's simplified employee pension plan. Contributions in 2003 included $259,323 recorded to combination cost and related expenses on the financial statements that is applicable to Dorchester Hugoton's severance payments made in January 2003 prior to closing of the combination.

*Severance Payments*—Dorchester Hugoton adopted a severance policy in 1998. Benefits were generally payable to employees and General Partner(s) in the event Dorchester Hugoton no longer existed, incurred reduction in force or eliminated a position or group of positions. Pursuant to the combination, approximately $2.7 million in severance payments were paid by Dorchester Hugoton in January 2003 prior to the closing of the combination which included $496,000 that was included in management fees on the financial statements.

*Operating Leases*—Dorchester Hugoton rented skid-mounted field gas compression units on a monthly basis and administrative office space under leases expiring at various dates through 2007. Total rental expense was $302,000 and $311,000 for the years ended December 31, 2002 and 2001 respectively.

*New Accounting Standards*—In July 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. Dorchester Minerals adopted SFAS No. 143 on January 1, 2003 which did not have a material effect on its financial statements.

We have been made aware that an issue has arisen within the industry regarding the application of provisions of Statement of Financial Accounting Standards No. 141, "Business Combinations," and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires companies to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, we and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties. Also under consideration is whether SFAS No. 142 requires companies to provide the additional disclosures prescribed by SFAS No. 142 for intangible assets for costs associated with mineral rights. A majority of the Partnership's oil and gas properties are perpetual in nature, so the applicability of SFAS 142 to these type of assets is not known at this time.

If it is ultimately determined that SFAS No. 142 requires us to reclassify costs associated with mineral rights from property and equipment to intangible assets, the amounts that would be reclassified would be immaterial to our financial position. The reclassification of these amounts would not affect the method in which such costs are amortized or the manner in which we assess impairment of capitalized costs. As a result, our cash flows and results of operations would not be affected by this reclassification.

**2. Combination Transaction**

On January 31, 2003, Dorchester Hugoton transferred certain assets to the operating partnership in exchange for a net profits interest, contributed the net profits interest and other assets to our Partnership and subsequently liquidated. Republic and Spinnaker transferred certain assets to the operating partnership in exchange for net profits interests and subsequently merged with our Partnership. For accounting purposes Dorchester Hugoton is deemed the acquirer. The value assigned to the assets of Republic and Spinnaker was based on the market capitalization of Dorchester Hugoton and the share of the total common units of our Partnership received by the

**DORCHESTER MINERALS, L.P.**
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**NOTES TO FINANCIAL STATEMENTS—(Continued)**
**December 31, 2003, 2002 and 2001**

former partners of Republic (10,953,078 common units) and Spinnaker (5,342,973 common units). The assets of Republic and Spinnaker were valued at $237,194,000 which was allocated as follows:

| | |
|---|---|
| Cash | $ 68,000 |
| Oil and gas properties | 233,466,000 |
| Receivables | 3,660,000 |
| Total | $ 237,194,000 |

The following reflects unaudited pro forma data related to the combination discussed herein. The unaudited pro forma data assumes the combination had taken place as of the beginning of each period. The pro forma amounts are not necessarily indicative of the results that may be reported in the future. Pro forma adjustments have been made to depletion, depreciation, and amortization to reflect the new basis of accounting for the assets of Spinnaker and Republic as of January 31, 2003, and to revenues to reflect the revenues of Dorchester Hugoton as Net Profits Interests.

| | Fiscal Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Revenues | $ 51,113 | $ 37,547 | $ 49,451 |
| Depletion | $ 25,390 | $ 25,844 | $ 24,753 |
| Impairment | $ 43,804 | — | — |
| Net earnings (loss) | $ (26,976) | $ 6,524 | $ 20,225 |
| Earnings (loss) per common unit | $ (0.97) | $ 0.24 | $ 0.74 |
| Nonrecurring items: | | | |
| Severance and related costs | $ 3,003 | — | — |
| Combination-related costs | $ 670 | $ 1,937 | $ 1,178 |

### 3. Related Party Transactions

Our general partner owns all of the partnership interests in Dorchester Minerals Operating LP, the operating partnership. It is the employer of all personnel, owns the working interests and other properties underlying our Net Profits Interests, and provides day-to-day operational and administrative services to us and the general partner. At December 31, 2003, we had a receivable from the operating partnership in the amount of $4,178,000, representing accrued net profits interest payments. In accordance with our partnership agreement, we reimburse the general partner for certain allocable costs, including rent, salaries, and employee benefit plans. These type of reimbursements are limited to 5% of distributions, plus certain costs previously paid. Through December 31, 2003, reimbursements paid or accrued to the general partner were $1,199,000, which is substantially below the 5% limit amount.

### 4. Loans And Long-Term Debt

In June 2002 Dorchester Hugoton repaid its bank borrowings and terminated its unsecured revolving credit agreement. The amount borrowed during 2002 and 2001 was $100,000.

**DORCHESTER MINERALS, L.P.**
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**NOTES TO FINANCIAL STATEMENTS—(Continued)**
**December 31, 2003, 2002 and 2001**

### 5. Commitments and Contingencies

Since its first annual payment in 1997, in May of each year Dorchester Hugoton paid an Oklahoma production payment (calculated through the prior February) that was based upon the difference between market gas prices compared to a table of rising prices and based upon a table of declining volumes. On August 9, 2001, Dorchester Hugoton paid $5,270,000 to acquire, effective March 1, 2001, the Oklahoma production payment.

In November 2001 Dorchester Hugoton concluded all payments pursuant to a settlement approved by the Federal Energy Regulatory Commission concerning refunds of Kansas ad valorem tax reimbursements by paying Panhandle Eastern Pipe Line Company approximately $285,000.

In January 2002, some individuals and an association called Rural Residents for Natural Gas Rights, referred to as RRNGR, sued Dorchester Hugoton, Ltd., Anadarko Petroleum Corporation, Conoco, Inc., XTO Energy Inc., ExxonMobil Corporation, Phillips Petroleum Company, Incorporated and Texaco Exploration and Production, Inc. The operating partnership, owned directly and indirectly by our general partner, now owns and operates the properties formerly owned by Dorchester Hugoton. These properties contribute a major portion of the Net Profits Interests amounts paid to our Partnership. The suit is currently pending in the District Court of Texas County, Oklahoma and discovery is underway by the plaintiffs and defendants. The individuals and RRNGR consist primarily of Texas County, Oklahoma residents who, in residences located on leases use natural gas from gas wells located on the same leases, at their own risk, free of cost. The plaintiffs seek declaration that their domestic gas use is not limited to stoves and inside lights and is not limited to a principal dwelling as provided in the oil and gas lease agreements with defendants in the 1930s to the 1950s. Plaintiffs' claims against defendants include failure to prudently operate wells, violation of rights to free domestic gas, violation of irrigation gas contracts, underpayment of royalties, a request for an accounting, and fraud. Plaintiffs also seek certification of class action against defendants. The operating partnership believes plaintiffs' claims are completely without merit. In July 2002, the defendants were granted a motion for summary judgment removing RRNGR as a plaintiff. Based upon past measurements of such gas usage, the operating partnership believes the damages sought by plaintiffs to be minimal. An adverse decision could reduce amounts our Partnership receives from the Net Profits Interests.

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

### 6. Impairment of Oil and Gas Properties

During the second and third quarters of 2003, our Partnership recorded non-cash charges against earnings totaling $43,804,000. The write-downs represent an impairment of assets that results primarily from the difference, after accumulated depletion, between the discounted present value of our Partnership's proved natural gas and oil reserves using quarter ending gas and oil prices as compared to the initial book value assigned to former Republic and Spinnaker assets in accordance with purchase accounting rules, which value significantly exceeded historic book value. Cash flow from operations and cash distributions to unitholders are not affected by the write-down. Please see Note 1.

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## 7. Distribution To Holders Of Common Units

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

| 2003 Quarter | Record Date | Payment Date | Amount |
|---|---|---|---|
| 1st (partial) | April 28, 2003 | May 8, 2003 | $0.206469 |
| 2nd | July 28, 2003 | August 7, 2003 | $0.458087 |
| 3rd | October 31, 2003 | November 10, 2003 | $0.422674 |
| 4th | January 26, 2004 | February 5, 2004 | $0.391066 |

The partnership agreement requires the next cash distribution to be paid by May 15, 2004.

## 8. Unaudited Natural Gas Reserve Information

Our Partnership retained Huddleston & Co., Inc. as an independent petroleum engineering consulting firm who performed similar prior studies for Republic Royalty and Spinnaker Royalty, to provide an annual estimate as of December 31, 2003 of the Royalty Properties future net recoverable oil and gas reserves. Similarly, the operating partnership retained Calhoun, Blair & Associates, Inc., an independent petroleum engineering consulting firm, who performed similar prior studies for Dorchester Hugoton, to provide an annual estimate as of December 31, 2003 of the Net Profits Interests future net recoverable oil and gas reserves. Dorchester Hugoton had no known reserves of crude oil. There have been no events that have occurred since December 31, 2003 that would have a material effect on the estimated proved developed natural gas reserves.

In accordance with SFAS No. 69 and Securities and Exchange Commission ("SEC") rules and regulations, the following information is presented with regard to the Net Profits Interests and Royalty Properties oil and gas reserves, all of which are proved, developed and located in the United States.

The SEC has adopted SFAS No. 69 disclosure guidelines for oil and gas producers. These rules require inclusion as a supplement to the basic financial statements a standardized measure of discounted future net cash flows relating to proved oil and gas reserves. The standardized measure, in management's opinion, should be examined with caution. The basis for these disclosures are independent petroleum engineer's reserve studies which contains imprecise estimates of quantities and rates of production of reserves. Revision of prior year estimates can have a significant impact on the results. Also, exploration and production improvement costs in one year may significantly change previous estimates of proved reserves and their valuation. Values of unproved properties and anticipated future price, and cost increases or decreases are not considered. Therefore, the standardized measure is not necessarily a "best estimate" of the fair value of oil and gas properties or of future net cash flows.

**DORCHESTER MINERALS, L.P.**
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**NOTES TO FINANCIAL STATEMENTS—(Continued)**
**December 31, 2003, 2002 and 2001**

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves developed by independent petroleum engineers.

**Summary of Changes in Proved Reserves**

| | Oil (mbbl) | Natural Gas (mmcf) | | |
|---|---|---|---|---|
| | 2003 | 2003 | 2002 | 2001 |
| Estimated quantity, beginning of year | — | 43,519 | 48,302 | 54,127 |
| Purchase of Minerals in place (1) | 4,036 | 29,307 | — | — |
| Revisions in previous estimates | 37 | 6,586 | 1,348 | 743 |
| Production (2) | (304) | (9,285) | (6,131) | (6,568) |
| Estimated quantity, end of year | 3,769 | 70,127 | 43,519 | 48,302 |

(1) Includes 4,035,822 bbls of oil and 30,610,400 mcf of gas attributable to properties acquired from Republic and Spinnaker as of January 31, 2003 less 1,303,736 mcf as an adjustment to reflect the 3.03% interest in the former Dorchester Hugoton properties now owned by the operating partnership.

(2) Includes 502,735 mcf of gas attributable to production by Dorchester Hugoton for the one month of January 2003 and 5,493,470 mcf of gas and 7,012 bbls of oil for the eleven months of 2003 attributable to the Net Profits Interests properties and 3,288,455 mcf of gas and 296,886 bbls of oil for the eleven months of 2003 attributable to the Royalty Properties.

**Standardized Measure of Discounted Future Net Cash Flows**
**(Dollars in Thousands)**

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Future estimated gross revenues | $ 428,860 | $ 185,213 | $ 117,029 |
| Future estimated production costs | (19,900) | (56,492) | (51,083) |
| Future estimated net revenues | 408,960 | 128,721 | 65,946 |
| 10% annual discount for estimated timing of cash flows | (175,138) | (39,012) | (21,220) |
| Standardized measure of discounted future estimated net cash flows | $ 233,822 | $ 89,709 | 44,726 |
| Sales of natural gas produced, net of production costs | $ (46,900) | $ (14,924) | (21,899) |
| Purchase of reserves in place | $ 137,136 | — | — |
| Net changes in prices and production costs | 24,434 | 47,101 | (89,233) |
| Revisions of previous quantity estimates | 17,170 | 8,671 | 3,488 |
| Accretion of discount | 8,971 | 3,938 | 12,471 |
| Other | 3,302 | 197 | (104) |
| Net change in standardized measure of discounted future estimated net cash flows | $ 144,113 | $ 44,983 | $ (95,277) |
| Depletion of oil and natural gas properties (dollars per mcfe) | $ 2.16 | $ 0.33 | $ 0.31 |
| Development costs incurred | $ 2 | $ 21 | $ 240 |
| Property acquisition costs | $ 233,466 | $ 148 | $ 5,297 |

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### 9. Unaudited Quarterly Financial Data

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

| | 2003 Quarter Ended | | | | 2002 Quarter Ended | | | |
|---|---|---|---|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 | March 31 | June 30 | September 30 | December 31 |
| Net operating revenues | $ 13,956 | $ 11,300 | $ 12,548 | $ 11,420 | $ 3,700 | $ 4,648 | $ 4,509 | $ 5,881 |
| Net earnings (loss) | $ 3,943 | $ (18,928) | $ (16,686) | $ 4,844 | $ 1,817 | $ 2,738 | $ 2,660 | $ 5,748 |
| Net earnings (loss) per Unit | $ 0.18 | $ (0.68) | $ (0.60) | $ 0.18 | $ 0.17 | $ 0.25 | $ 0.24 | $ 0.53 |
| Weighted average common units outstanding (000's) | 21,608 | 27,040 | 27,040 | 27,040 | 10,744 | 10,744 | 10,744 | 10,744 |

Exhibit 21.1

1. Dorchester Minerals Oklahoma LP, an Oklahoma limited partnership
2. Dorchester Minerals Oklahoma GP, Inc. an Oklahoma corporation

Exhibit 31.1

CERTIFICATION

I, William Casey McManemin, Chief Executive Officer of Dorchester Minerals Management GP LLC, General Partner of Dorchester Minerals Management LP, General Partner of Dorchester Minerals, L.P., (the "Registrant"), certify that:

1. I have reviewed this annual report on Form 10-K of Dorchester Minerals, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this report;
4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15 (e) and 15d-15(e)) for the Registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   c) Disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and
5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

/s/ William Casey McManemin
William Casey McManemin
Chief Executive Officer

Date: March 8, 2004

Exhibit 31.2

CERTIFICATION

I, H.C. Allen, Jr., Chief Financial Officer of Dorchester Minerals Management GP LLC, General Partner of Dorchester Minerals Management LP, General Partner of Dorchester Minerals, L.P., (the “Registrant”), certify that:

1. I have reviewed this annual report on Form 10-K of Dorchester Minerals, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this report;
4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15 (e) and 15d-15(e)) for the Registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    c) Disclosed in this report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and
5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

/s/ H.C. Allen, Jr.
H.C. Allen, Jr.
Chief Financial Officer

Date: March 8, 2004

Exhibit 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

In connection with the accompanying Annual Report of Dorchester Minerals, L.P., (the “Partnership”) on Form 10-K for the period ended December 31, 2003 (the “Report), I, William Casey McManemin, Chief Executive Officer of Dorchester Minerals Management GP LLC, General Partner of Dorchester Minerals Management LP, General Partner of the Partnership, hereby certify that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William Casey McManemin
William Casey McManemin
Chief Executive Officer

Date: March 8, 2004

Exhibit 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

In connection with the accompanying Annual Report of Dorchester Minerals, L.P., (the “Partnership”) on Form 10-K for the period ended December 31, 2003 (the “Report), I, H.C. Allen, Jr., Chief Financial Officer of Dorchester Minerals Management GP LLC, General Partner of Dorchester Minerals Management LP, General Partner of the Partnership, hereby certify that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ H.C. Allen, Jr.
H.C. Allen, Jr.
Chief Financial Officer

Date: March 8, 2004