MESA ROYALTY TRUST/TX
Form 10-K
April 06, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2007**

Or

o **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: 1-7884

Mesa Royalty Trust

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**76-6284806** (I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A., Trustee **919 Congress Avenue, Austin, Texas** (Address of principal executive offices)	**78701** (Zip Code)

Registrant's telephone number, including area code: **800-852-1422**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Units of Beneficial Interest	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

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

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

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 o No ý

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 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. ý

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

Large accelerated filer o Accelerated filer ý Non-accelerated filer o Smaller Reporting Company o

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

The aggregate market value of 1,863,590 Units of Beneficial Interest in Mesa Royalty Trust held by non-affiliates of the registrant at the closing sales price on June 30, 2008 of $82.50 was approximately $153,746,175.

As of March 31, 2009, 1,863,590 Units of Beneficial Interest were outstanding in Mesa Royalty Trust.

DOCUMENTS INCORPORATED BY REFERENCE: None

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Note Regarding Forward-Looking Statements

This Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-K are forward-looking statements. Although the Working Interest Owners have advised the Trust that they believe that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations ("Cautionary Statements") are disclosed in this Form 10-K, including without limitation in conjunction with the forward-looking statements included in this Form 10-K. A consolidated summary description of principal risk factors that could cause actual results to differ is also set forth in this Form 10-K under "Item 1A. Risk Factors." All subsequent written and oral forward-looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements.

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PART I

Item 1. Business.

DESCRIPTION OF THE TRUST

The Mesa Royalty Trust (the "Trust"), created under the laws of the State of Texas, maintains its offices at the office of the Trustee, The Bank of New York Trust Company, N.A., (the "Trustee"), 919 Congress Avenue, Austin, Texas 78701. The telephone number of the Trust is 1-800-852-1422. The Bank of New York Trust Company, N.A., is the successor Trustee from JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank and is the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association.

The Trustee does not maintain a website for filings by the Trust with the U.S. Securities and Exchange Commission ("SEC"). Electronic filings by the Trust with the SEC are available free of charge through the SEC's website at *www.sec.gov*.

The Trust was created on November 1, 1979 when Mesa Petroleum Co. conveyed to the Trust an overriding royalty interest (the "Royalty") equal to 90% of the Net Proceeds (as defined in the Conveyance and described below) attributable to the specified interests in properties conveyed by the assignor on that date (the "Subject Interests"). The Subject Interests consisted of interests in certain oil and gas properties located in the Hugoton field of Kansas, the San Juan Basin field of New Mexico and Colorado, and the Yellow Creek field of Wyoming (collectively, the "Royalty Properties"). The Royalty is evidenced by counterparts of an Overriding Royalty Conveyance dated as of November 1, 1979 (the "Conveyance"). Mesa Petroleum Co. was the predecessor to Mesa Limited Partnership ("MLP"), which was the predecessor to MESA Inc. On April 30, 1991, MLP sold its interests in the Royalty Properties located in the San Juan Basin field to ConocoPhillips, successor by merger to Conoco Inc. ("ConocoPhillips"). ConocoPhillips sold most of its interests in the San Juan Basin Royalty Properties located in Colorado to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP Amoco Company ("BP"), a subsidiary of BP p.l.c. Until August 7, 1997, MESA Inc. operated the Hugoton Royalty Properties through Mesa Operating Co., a wholly owned subsidiary of MESA Inc. On August 7, 1997, MESA Inc. merged with and into Pioneer Natural Resources Company ("Pioneer"), formerly a wholly owned subsidiary of MESA Inc., and Parker & Parsley Petroleum Company merged with and into Pioneer Natural Resources USA, Inc. (successor to Mesa Operating Co.), a wholly owned subsidiary of Pioneer ("PNR") (collectively, the mergers are referred to herein as the "Merger"). Subsequent to the Merger, the Hugoton Royalty Properties have been operated by PNR. All of the San Juan Basin Royalty Properties located in New Mexico and a few wells in Southwest Colorado, near the New Mexico border, are operated by ConocoPhillips. Substantially all of the San Juan Basin Royalty Properties located in Colorado are operated by BP. As used in this report, PNR refers to the operator of the Hugoton Royalty Properties, ConocoPhillips refers to the operator of the New Mexico San Juan Basin Royalty Properties and BP refers to the operator of the Colorado San Juan Basin Royalty Properties, unless otherwise indicated. The terms "working interest owner" and "working interest owners" generally refer to the operators of the Royalty Properties as described above, unless the context in which such terms are used indicates otherwise.

The terms of the Mesa Royalty Trust Indenture (the "Trust Indenture") provide, among other things, that: (1) the Trust cannot engage in any business or investment activity or purchase any assets; (2) the Royalty can be sold in part or in total for cash upon approval of the unitholders; (3) the Trustee can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of the borrowings; (4) in January, April, July and October of each year the Trustee will make quarterly distributions of cash available for distribution to the unitholders; and (5) the Trust will terminate upon the first to occur of the following events: (i) at such time as the Trust's royalty income for each of two successive years is less than $250,000 per year or (ii) a vote of the unitholders in favor of termination. Royalty income of the Trust was $12,216,271 and $9,809,030 for the years 2007 and 2006, respectively. Upon termination of the Trust, the Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to unitholders of any funds remaining after all Trust liabilities have been satisfied.

Under the Conveyance, the Trust is entitled to payment of 90% of the Net Proceeds (as defined in the Conveyance), realized from Subject Minerals (as defined in the Conveyance) as, if and when produced from the Royalty Properties. See "Description of Royalty Properties." The Conveyance provides for a monthly computation of Net Proceeds. "Net Proceeds" is defined in the Conveyance as the excess of Gross Proceeds (as defined in the Conveyance), received by the working interest owners during a particular period over operating and capital costs for such period. "Gross Proceeds" is defined in the Conveyance as the amount received by the working interest owners from the sale of Subject Minerals, subject to certain adjustments. Subject Minerals mean all oil, gas and other minerals, whether similar or dissimilar, in and under, and which may be produced, saved and sold from, and which accrue and are attributable to, the Subject Interests from and after November 1, 1979. Operating costs mean, generally, costs incurred on an accrual basis by the working interest owners in operating the Royalty Properties, including capital and non-capital costs. If operating and capital costs exceed Gross Proceeds for any month, the excess plus interest thereon at 120% of the prime rate of Bank of America is recovered out of future Gross Proceeds prior to the making of further payment to the Trust. The Trust, however, is generally not liable for any operating costs or other costs or liabilities attributable to the Royalty Properties or minerals produced therefrom. The Trust is not obligated to return any royalty income received in any period. The working interest owners are required to maintain books and records sufficient to determine the amounts payable under the Royalty. Additionally, in the event of a controversy between a working interest owner and any purchaser as to the correct sales price for any production, amounts received by such working interest owner and promptly deposited by it with an escrow agent are not considered to have been received by such working interest owner and therefore are not subject to being payable with respect to the Royalty until the controversy is resolved; but all amounts thereafter paid to such working interest owner by the escrow agent will be considered amounts received from the sale of production. Similarly, operating costs include any amounts a working interest owner is required to pay whether as a refund, interest or penalty to any purchaser because the amount initially received by such working interest owner as the sales price was in excess of that permitted by the terms of any applicable contract, statute, regulation, order, decree or other obligation. Within 30 days following the close of each calendar quarter, the working interest owners are required to deliver to the Trustee a statement of the computation of Net Proceeds attributable to such quarter.

The brief discussions of the Trust Indenture and the Conveyance contained herein are qualified in their entirety by reference to the Trust Indenture and the Conveyance themselves, which are exhibits to this Form 10-K and are available upon request from the Trustee.

The Royalty Properties are required to be operated by the working interest owners in accordance with reasonable and prudent business judgment and good oil and gas field practices. Each working interest owner has the right to abandon any well or lease if, in its opinion, such well or lease ceases to produce or is not capable of producing oil, gas or other minerals in commercial quantities. Each working interest owner markets the production on terms deemed by it to be the best reasonably obtainable in the circumstances. See "Contracts." The Trustee has no power or authority to exercise any control over the operation of the Royalty Properties or the marketing of production therefrom.

In 1985, the Trust Indenture was amended at a special meeting of unitholders and the Trust conveyed to an affiliate of Mesa Petroleum Co. 88.5571% of the original Royalty (such transfer, the "1985 Assigment"). The effect of the assignment was an overall reduction of approximately 88.56% in the size of the Trust, distributable income and related Trust reserves, effective April 1, 1985. See Note 2 in the Notes to Financial Statements under Item 8 of this Form 10-K.

The Trust has no employees. Administrative functions of the Trust are performed by the Trustee.

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DESCRIPTION OF THE UNITS

Each unit is evidenced by a transferable certificate issued by the Trustee. Each unit ranks equally for purposes of distributions and has one vote on any matter submitted to unitholders. A total of 1,863,590 units were outstanding at March 31, 2009.

Distributions

The Trustee determines for each month the amount of cash available for distribution for such month. Such amount (the "Monthly Distribution Amount") consists of the cash received from the Royalty during such month less the obligations of the Trust paid during such month, adjusted for changes made by the Trustee during such month in any cash reserves established for the payment of contingent or future obligations of the Trust. The Monthly Distribution Amount for each month is payable to unitholders of record on the monthly record date (the "Monthly Record Date"), which is the close of business on the last business day of such month or such other date as the Trustee determines is required to comply with legal or stock exchange requirements. However, to reduce the administrative expenses of the Trust, under the Trust Indenture the Trustee does not distribute cash monthly, but rather, during January, April, July and October of each year distributes to each person who was a unitholder of record on one or more of the immediately preceding three Monthly Record Dates, the Monthly Distribution Amount for the month or months that he was a unitholder of record, together with interest earned on such Monthly Distribution Amount from the Monthly Record Date to the payment date. Under the terms of the Trust Indenture, interest is earned at a rate of $1^1/_2$% below the prime rate charged by The Bank of New York Trust Company, N.A., successor from JPMorgan Chase Bank, N.A., (as the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association) or the interest rate which The Bank of New York Trust Company, N.A., pays in the normal course of business on amounts placed with it, whichever is greater.

Liability of Unitholders

In regards to the unitholders, the Trustee is fully liable if the Trustee incurs any liability without ensuring that such liability will be satisfiable only out of the Trust assets (regardless of whether the assets are adequate to satisfy the liability) and in no event out of amounts distributed to, or other assets owned by, unitholders. However, under Texas law, it is unclear whether a unitholder would be jointly and severally liable for any liability of the Trust in the event that all of the following conditions were to occur: (1) the satisfaction of such liability was not by contract limited to the assets of the Trust, (2) the assets of the Trust were insufficient to discharge such liability and (3) the assets of the Trustee were insufficient to discharge such liability. Although each unitholder should weigh this potential exposure in deciding whether to retain or transfer his units, the Trustee is of the opinion that because of the passive nature of the Trust assets, the restrictions on the power of the Trustee to incur liabilities and the required financial net worth of any trustee, the imposition of any liability on a unitholder is extremely unlikely.

Federal Income Tax Matters

This section is a summary of federal income tax matters of general application which addresses the material tax consequences of the ownership and sale of the units. Except where indicated, the discussion below describes general federal income tax considerations applicable to individuals who are citizens or residents of the United States. Accordingly, the following discussion has limited application to domestic corporations and persons subject to specialized federal income tax treatment, such as regulated investment companies and insurance companies. It is impractical to comment on all aspects of federal, state, local and foreign laws that may affect the tax consequences of the transactions contemplated hereby and of an investment in the units as they relate to the particular circumstances of every unitholder. **Each unitholder is encouraged to consult its own tax advisor with respect to its particular circumstances.**

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This summary is based on current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed Treasury Regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may or may not be retroactively applied. Some of the applicable provisions of the Code have not been interpreted by the courts or the Internal Revenue Service (the "IRS"). No assurance can be provided that the statements set forth herein (which do not bind the IRS or the courts) will not be challenged by the IRS or will be sustained by a court if so challenged.

Classification of the Trust

In a technical advice memorandum dated February 26, 1982, the National Office of the IRS advised the Dallas District Director that the Trust is classifiable as a grantor trust and not as an association taxable as a corporation. As a grantor trust, the Trust will incur no federal income tax liability.

The Trustee assumes that some Trust Units are held by a middleman, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. Bank of New York Trust Company, N.A., 919 Congress Avenue, Austin, Texas 78701, telephone number 1-800-852-1422, is the representative of the Trust that will provide tax information beginning with the 2008 tax year in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT.

Income and Depletion

Royalty income, net of depletion and severance taxes, is portfolio income. Subject to certain exceptions and transitional rules, royalty income cannot be offset by passive losses. Additionally, interest income is portfolio income. Administrative expense is an investment expense.

Generally, prior to the Revenue Reconciliation Act of 1990, the transferee of an oil and gas property could not claim percentage depletion with respect to production from the property if it was "proved" at the time of the transfer. This rule is not applicable in the case of transfers of properties after October 11, 1990. Thus, eligible unitholders who acquired units after that date are entitled to claim an allowance for percentage depletion with respect to royalty income attributable to these units to the extent that this allowance exceeds cost depletion as computed for the relevant period.

Backup Withholding

Distributions from the Trust are generally subject to backup withholding at a rate of 28% of these distributions. Backup withholding will not normally apply to distributions to a unitholder, however, unless the unitholder fails to properly provide to the Trust his taxpayer identification number or the IRS notifies the Trust that the taxpayer identification number provided by the unitholder is incorrect.

Sale of Units

Generally, except for recapture items, the sale, exchange or other disposition of a unit will result in capital gain or loss measured by the difference between the tax basis in the unit and the amount realized. Effective for property placed in service after December 31, 1986, the amount of gain, if any, realized upon the disposition of oil and gas property is treated as ordinary income up to the amount of intangible drilling and development costs incurred with respect to the property and depletion claimed to the extent it reduced the taxpayer's basis in the property. Under this provision, depletion attributable to a unit acquired after 1986 will be subject to recapture as ordinary income upon disposition of the unit or upon disposition of the oil and gas property to which the depletion is attributable. The balance of any gain or any loss will be capital gain or loss if the unit was held by the unitholder as a capital

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asset, either long-term or short-term depending on the holding period of the unit. This capital gain or loss will be long-term if a unitholder's holding period exceeds one year at the time of sale or exchange. The long-term capital gain rate applicable to most capital assets with a holding period of more than one year is 15%, but that rate is currently scheduled to expire December 31, 2010. Without Congressional action, for taxable years beginning on or after January 1, 2011, the long-term capital gain rate is scheduled to increase to 20%. Capital gain or loss will be short-term if the unit has not been held for more than one year at the time of sale or exchange.

Non-U.S. Unitholders

In general, a unitholder who is a nonresident alien individual or which is a foreign corporation, each a "non-U.S. unitholder" for purposes of this discussion, will be subject to tax on the gross income (without taking into account any deductions, such as depletion) produced by the Royalty at a rate equal to 30% or, if applicable, at a lower treaty rate. This tax will be withheld by the Trustee and remitted directly to the United States Treasury. A non-U.S. unitholder may elect to treat the income from the Royalty as effectively connected with the conduct of a United States trade or business under provisions of the Code or pursuant to any similar provisions of applicable treaties. Upon making this election a non-U.S. unitholder is entitled to claim all deductions with respect to that income, but he must file a United States federal income tax return to claim these deductions. This election once made is irrevocable unless an applicable treaty allows the election to be made annually.

The Code and the Treasury Regulations thereunder treat the publicly traded Trust as if it were a United States real property holding corporation. Accordingly, non-U.S. unitholders may be subject to United States federal income tax on the gain on the disposition of their units.

Federal income taxation of a non-U.S. unitholder is a highly complex matter which may be affected by many considerations. Therefore, each non-U.S. unitholder is encouraged to consult with his own tax adviser with respect to its ownership of units.

Tax-Exempt Organizations

The Royalty and interest income should not be unrelated business taxable income so long as, generally, a unitholder did not incur debt to acquire a unit or otherwise incur or maintain a debt that would not have been incurred or maintained if the unit had not been acquired. Legislative proposals have been made from time to time which, if adopted, would result in the treatment of Royalty income as unrelated business taxable income. Each tax-exempt unitholder is encouraged to consult its own advisor with respect to the treatment of royalty income.

DESCRIPTION OF ROYALTY PROPERTIES

Producing Acreage and Wells as of December 31, 2007

	Producing Acres(1)		Producing Gas Wells(1)	
	Gross	**Net**	**Gross**	**Net**
Hugoton Area (Kansas)	99,654	99,413	466	466
San Juan Basin (Northwestern New Mexico and Southwestern Colorado)	40,716	31,328	1,237	466
Total	140,370	130,741	1,703	932

(1) The Trust does not have a working interest in the producing acres and producing gas wells. The gross and net amounts in the table above represent gross and net amounts attributable to the working interest owners and are the basis for the Gross Proceeds amounts discussed under "Description of the Trust."

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Hugoton

The principal property interest conveyed to the Trust accounts for approximately 20% of the Trust's reserves and was carved out of PNR's working interest in 104,437 net producing acres in the Hugoton field. The life of the field is expected to extend beyond the year 2020.

The gas produced from the Hugoton properties is available for sale on the spot market. See "Contracts." Since the Hugoton field gas is sold in the intrastate and interstate markets, it is subject to state and federal laws and regulations. The Kansas Corporation Commission (the "KCC") is the state regulatory agency responsible for setting field market demand (gas allowables), prorating production between wells and other related matters. Hugoton field gas is also subject to the rules and regulations of the Federal Energy Regulatory Commission (the "FERC"). See "Regulation and Prices."

San Juan Basin

The Trust's interest in the San Juan Basin was conveyed from PNR's working interest in 31,328 net producing acres in northwestern New Mexico and southwestern Colorado. The San Juan Basin-New Mexico reserves, including a few wells located in Southwestern Colorado, retained by ConocoPhillips represent approximately 54% of the Trust's reserves. Substantially all of the natural gas produced from the San Juan Basin is currently being sold on the spot market. PNR completed the sale of its underlying interest in the San Juan Basin Royalty Properties to ConocoPhillips on April 30, 1991. ConocoPhillips subsequently sold its underlying interest in substantially all of the Colorado portion of the San Juan Basin Royalty Properties to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP. See " Description of the Trust" under Item 1 of this Form 10-K. The San Juan Basin Royalty Properties located in Colorado account for approximately 5% of the Trust's reserves.

San Juan Basin Fruitland Coal Drilling

In April 1990, the working interest owner began drilling for coalbed methane gas in the Fruitland Coal formation of the San Juan Basin. The Fruitland Coal formation has been identified as one of the most prolific sources of U.S. coalbed methane reserves. The Trust owns an interest in 26,700 gross acres and 25,400 net acres with Fruitland Coal potential. The working interest owner has advised the Trust that, as of December 31, 2007, the working interest owner had drilled on Trust properties 50 (29.3 net) Fruitland Coal wells, all of which are operated by the working interest owner. Of the wells drilled on Trust properties, 49 (34.8 net) are currently producing at a combined rate of 35 (16.1 net) MMcf per day.

The gas that is currently being produced from these wells is being sold on the spot market, although the working interest owner has advised the Trust that it will also consider selling some of the gas produced from these wells pursuant to longer term contracts at spot market prices.

Aggregate drilling and completion costs for the entire Fruitland Coal development program were approximately $18,400,000. The Trust's share of the total expenditures was approximately $2,400,000. The Trust's share of the cost of drilling and completing the Fruitland Coal wells was subject to recovery by the working interest owner on a state-by-state basis before distributions were made from the San Juan Basin Royalty. In December 1992, after recovery by the working interest owner of the costs of the Fruitland Coal drilling in New Mexico, distributions from the New Mexico portion of the San Juan Basin Royalty resumed. No distributions related to the Colorado portion of the San Juan Basin Royalty were made from 1990 until December 2006. The costs related to the San Juan Basin, Colorado portion were recovered in December 2004. However, subsequent earnings were not remitted to the Trust until December 2006 and July 2007. The cumulative earnings, including interest on undistributed earnings, reported to the Trust by the Working Interest Owner through November 2006, totaled $1,280,412. In December 2006, BP remitted $978,349 for payment of undistributed earnings from January 2005

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through October 2006 and November 2006 earnings for the San Juan properties it operates. In July 2007, Red Willow remitted $159,497 for payment of undistributed earnings from January 2005 through December 2006 for the properties it operates. BP communicated to the Trust that these distributions represent all of the previously unpaid revenues. The Trustee is currently investigating the $142,566 difference in the original estimate of unpaid proceeds of $1,280,412 and the remaining payments of $1,137,846.

Reserves

Hugoton Area

The information included in this Form 10-K about the Trust's proved oil and gas reserves attributable to the Hugoton Royalty as of December 31, 2007 is based on evaluations prepared by internal engineers of PNR, the operator of the Hugoton Royalty Properties, as of that date, and were not prepared by any independent engineering or consulting firm. References to the reserves of the Trust and the future net revenue and present worth attributable to the Trust interest below refer to the Trust's interest in the Hugoton Royalty Properties. The estimated reserve quantities and future net revenue are based upon a month of production without regard to time of receipt by the Trust and differs from the basis in which the Trust recognizes and accounts for its Royalty income.

The following table is based on the information provided by PNR, as noted above, and summarizes estimates of the net proved reserves attributable to the Trust in the Hugoton Royalty Properties as of December 31, 2007.

Total Proved Reserves:

Natural Gas Liquids (bbl)	368,123
Natural Gas (Mcf)	8,181,527

	Proved Reserves ($000)
Future Gross Revenue	102,308
Operating Expenses	26,043
Capital Expenses	191
Future Net Revenue*	76,074
Present Worth at 10 Percent*	35,064

* Future income taxes were not taken into account in the preparation of these estimates.

The reserve estimates provided by PNR noted above were set forth in a letter dated March 12, 2008 to the Trustee. All of the foregoing proved reserves were also categorized as proved developed reserves. The development status shown was based on the status applicable on December 31, 2007. Proved natural gas liquid reserves are included in the estimates for the Satanta plant, which was completed and placed on stream in the Hugoton field during late 1993. Gross production estimated to December 31, 2007 was deducted from gross ultimate recovery to arrive at the estimates of gross reserves as of December 31, 2007. In these fields, this required that the production rates be estimated for up to three months, since production data for certain properties were available only through September 2007. PNR is continuing to upgrade the well gathering system, which improves deliverability of the wells, and this increase in deliverability and the associated costs were incorporated into the foregoing estimates.

San Juan Basin

A study of the proved San Juan Basin oil and gas reserves attributable to the Trust has been made by DeGolyer and MacNaughton, independent petroleum engineering consultants, as of December 31,

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2007 (the "San Juan Reserve Report"). The San Juan Basin Reserve Report reflects estimated production, reserve quantities and future net revenue based upon estimates of the future timing of actual production without regard to when received in cash by the Trust, which differs from the manner in which the Trust recognizes and accounts for its Royalty income.

The following tables are based on the information contained in the San Juan Reserve Report and summarize (1) estimates of the Trust's proved reserves as of December 31, 2007, and (2) the estimated future revenue and costs attributable to the Trust's Royalty interest in total proved reserves, as of December 31, 2007, of the properties evaluated.

Total Proved Reserves:

Oil and Natural Gas Liquids (Bbl)	541,589
Gas (Mcf)	9,240,556

	Proved Reserves ($000)
Future Gross Revenue	78,041
Operating Expenses	10
Future Net Revenue*	78,031
Present Worth at 10 Percent*	38,688

* Future income tax expenses were not taken into account in the preparation of these estimates.

The San Juan Reserve Report was delivered to the Trustee on April 3, 2009. All of the foregoing proved reserves in this report were also categorized as proved developed reserves. Net reserves of the Trust's Royalty are calculated at the aggregate level from the net revenue of each of the Working Interest Owners. To estimate net gas reserves, the total net revenue is divided by the net value of 1 Mcf of gas. The net value of 1 Mcf of gas is the gas price per Mcf, plus the condesate value per Mcf of gas, plus the NGL value per Mcf of gas. The net condensate and NGL reserves are calculated by multiplying their respective yields by the net gas reserves. Revenue values used in the San Juan Reserve Report were estimated using the following prices: (1) condensate prices - $92.35 per bbl; (2) NGL prices - $49.46 per bbl; and (3) natural gas prices - $5.48 per Mcf, with the initial prices also used as weighted average prices held constant thereafter over the lives of the properties. Estimates of operating expenses were based on current expenses and used for the life of the properties with no increases in the future based on inflation.

The December 31, 2007 reserve estimates for the San Juan Basin properties were prepared by a third party reservoir engineering firm, whereas the December 31, 2006 and 2005 reserve estimates were prepared by the Working Interest Owner. To the best knowledge of the Trustee after inquiry, revisions to previous estimates in 2007 are primarily due to professional differences in judgment regarding estimate of San Juan Basin reserves.

General Matters Regarding Reserve Estimates

For further information regarding the Net Overriding Royalty Interest, the Basis of Accounting and Supplemental Reserve Information, see Notes 2, 3 and 7, respectively, in the Notes to Financial Statements contained in Item 8 of this Form 10-K.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures, including many factors beyond the control of the producer. Reserve data included above and in these reports represent estimates only and should not be construed as being exact. The discounted present values shown by the reserve reports should not be construed as the current market value of the estimated gas and oil reserves attributable to the Royalty Properties or the costs that would be incurred to obtain equivalent reserves, since a market value determination would include many additional factors.

The Trustee has been advised that each of the foregoing estimates were prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board. Accordingly, the estimates are based on existing economic and operating conditions in effect at October 31, 2007, with no provision for future increases or decreases except for periodic price redeterminations in accordance with existing gas contracts. Actual future prices and costs may be materially greater or less than the assumed amounts in the reserve reports. Because the reserve reports are limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved are not included in the calculation of estimated future net revenues. Reserve assessment is a subjective process of estimating the recovery from underground accumulations of gas and oil that cannot be measured in an exact way, and estimates of other persons might differ materially from those of PNR and DeGolyer and MacNaughton. Accordingly, reserve estimates are often different from the quantities of hydrocarbons that are ultimately recovered.

As noted above in this report, the Trustee is currently investigating certain payments and differences from original estimates. The Trustee is also reviewing, with the assistance of outside experts, prior allocations of payments of Royalty income by the working interest owners. Any past practices not consistent with the Conveyance could also cause the basis for the reserve estimates included above to differ from actual reserve quantities and future net revenues.

Income, Production and Average Prices

Reference is made to "Summary of Royalty Income, Production and Average Prices" under Item 7 of this Form 10-K for information concerning income, production and prices with respect to the Royalty.

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CONTRACTS

Hugoton Field

Natural gas and natural gas liquids produced by PNR from the Hugoton field and attributable to the Royalty accounted for approximately 47% of the Royalty income of the Trust during 2007.

PNR has advised the Trust that since June 1, 1995 natural gas produced from the Hugoton field has generally been sold under short-term and multi-month contracts at market clearing prices to multiple purchasers. During 2007, these purchasers included Greely Gas and Oneok Gas Marketing, Inc. PNR has advised the Trust that it expects to continue to market gas production from the Hugoton field under short-term and multi-month contracts. Overall market prices received for natural gas from Hugoton Royalty Properties were lower for the year-ended December 31, 2007 as compared to the year-ended December 31, 2006.

In June 1994, PNR entered into a gas transportation agreement (the "Gas Transportation Agreement") with Western Resources, Inc. ("WRI") for a primary term of five years commencing June 1, 1995. This contract has been continued in effect on a year-to-year basis since June 1, 2001. PNR extended the contract to June 1, 2009. Pursuant to the Gas Transportation Agreement, WRI agreed to compress and transport up to 160 MMcf per day of gas and redeliver such gas to PNR at the inlet of PNR's Satanta Plant. PNR agreed to pay WRI a fee of $0.06 per Mcf escalating 4% annually as of June 1, 1996. This Gas Transportation Agreement has been assigned to Kansas Gas Service ("Oneok").

Beginning July 1, 2007, the Hugoton and Panoma fields are considered a single, common source of supply and operate under a single combined Basic Proration Order (BPO). After July 1, 2007, the wells in each of these fields are allowed to produce at their open flow potential and will no longer be subject to allowable restrictions and any and all average or underage that a well may have accrued will be cancelled.

San Juan Basin

Natural gas, oil, condensate and natural gas liquids produced from the San Juan Basin field and attributable to the Royalty accounted for approximately 53% of the Royalty income of the Trust during 2007. The majority of gas produced from the San Juan Basin is now being sold on the spot market.

Market for Natural Gas

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for natural gas produced from the Royalty Properties and the quantities of gas sold. The natural gas industry in the United States during the 1990's was affected generally by a surplus in natural gas deliverability compared to demand. Demand for gas declined during this period due to a number of factors including the implementation of energy conservation programs, a shift in economic activity away from energy intensive industries and competition from alternative fuel sources such as residual fuel oil, coal and nuclear energy. Since 2000, demand for natural gas has increased while supplies from production have remained tight. Average annual wellhead prices increased from $5.49 per Mcf in 2004 to $7.51 per Mcf in 2005, decreased to $6.42 per Mcf in 2006 and were $6.37 per Mcf in 2007 according to Natural Gas Monthly published by the Energy Information Administration of the Department of Energy.

Due to the seasonal nature of demand for natural gas and its effects on sales prices and production volumes, the amounts of cash distributions by the Trust may vary substantially on a seasonal basis. Generally, production volumes and prices are higher during the first and fourth quarters of each calendar year due primarily to peak demand in these periods. Because of the time lag between the date on which the working interest owners receive payment for production from the Royalty Properties and

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the date on which distributions are made to unitholders, the seasonality that generally affects production volumes and prices is generally reflected in distributions to unitholders in later periods.

Competition

The production and sale of gas in the Hugoton field and San Juan Basin areas is highly competitive, and the working interest owners' competitors in these areas include the major oil and gas companies, independent oil and gas companies, and individual producers and operators. There are numerous producers in the Hugoton field and the San Juan Basin areas. The working interest owners have advised the Trust that they believe that their competitive position in their respective areas is affected by price, contract terms and quality of service. PNR has also advised the Trust that it believes that its competitive position in the Hugoton field is enhanced by virtue of its substantial holdings and ownership and control of its wells, gathering systems and processing plant. Market conditions in the San Juan Basin are negatively affected by the fact that most of the gas produced from such areas is transported on one of only two major pipelines, and the transportation of such gas is generally controlled by a small number of distribution companies.

REGULATION AND PRICES

General

The production and sale of natural gas from the Royalty Properties are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by price controls, taxes, conservation, safety, environmental and other laws relating to the petroleum industry, by changes in such laws and by constantly changing administrative regulations.

FERC Regulation

In general, the FERC regulates the transportation of natural gas in interstate commerce by interstate pipelines. Over the course of approximately the previous decade, the FERC adopted regulations resulting in a restructuring of the natural gas industry. The principle elements of this restructuring were the requirement that interstate pipelines separate, or "unbundle," into individual components the various services offered on their systems, with all transportation services to be provided on a non-discriminatory basis, and the prohibition against an interstate pipeline providing gas sales services except through separately-organized affiliates. In various rulemaking proceedings following its initial unbundling requirement, the FERC has refined its regulatory program applicable to interstate pipelines in various respects, and it has announced that it will continue to monitor these regulations to determine whether further changes are needed. As to these various developments, the working interest owners have advised the Trust that the on-going and evolving nature of these regulatory initiatives makes it impossible to predict their ultimate impact on the prices, markets or terms of sale of natural gas related to the Trust.

State and Other Regulation

All of the jurisdictions in which the Trust has an interest in producing oil and gas properties have statutory provisions regulating the production and sale of crude oil and natural gas. The regulations often require permits for the drilling of wells but extend also to the spacing of wells, the prevention of waste of oil and gas resources, the rate of production, prevention and clean-up of pollution and other matters. See "Contracts Hugoton Field" for a discussion of PNR's allowables in the Hugoton Royalty Properties.

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take requirements. For example, Oklahoma and Kansas have enacted

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a prohibition against discriminatory gathering rates. In addition, certain Texas regulatory officials have expressed interest in evaluating similar rules, but to date no actions have been taken towards regulatory gathering rates in the state.

Natural gas pipeline facilities used for the transportation of natural gas in interstate commerce are subject to Federal minimum safety requirements. These requirements, however, are not applicable to, *inter alia*, (1) onshore gathering facilities outside (i) the limits of any incorporated or unincorporated city, town, or village, and (ii) any designated residential or commercial area; or (2) pipeline facilities on the Outer Continental Shelf ("OCS") upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator. *See* 49 C.F.R. § 192.1(b). We are informed that the Royalty Properties are located in the Hugoton field in Kansas, the San Juan Basin in New Mexico and Colorado, and the Yellow Creek field of Wyoming. Furthermore, those states have adopted the Federal minimum safety requirements for intrastate pipelines within their borders. The standards governing pipeline safety have undergone recent changes and it is possible that future changes in the regulations and statutes may occur which may increase the stringency of the standards or expand the applicability of the standards to facilities not currently covered.

Environmental Matters

The working interest owners' operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment, including the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA" or "Superfund"), the Solid Waste Disposal Act, the Clean Air Act, and the Federal Water Pollution Control Act. These laws and regulations, including their state counterparts, can impose liability upon the lessee under a lease for the cost of cleanup of discharged materials resulting from a lessee's operations or can subject the lessee to liability for damages to natural resources. Violations of environmental laws, regulations, or permits can result in civil and criminal penalties as well as potential injunctions curtailing operations in affected areas and restrictions on the injection of liquids into the subsurface that may contaminate groundwater. The working interest owners have advised the Trust that they maintain insurance for costs of cleanup operations, but they are not fully insured against all such risks. A serious release of regulated materials could result in the U.S. Department of the Interior requiring lessees under federal leases to suspend or cease operations in the affected area. In addition, the recent trend toward stricter standards and regulations in environmental legislation is likely to continue. For example, from time to time legislation has been proposed in Congress that would reclassify certain oil and gas production wastes as "hazardous wastes" which would subject the handling, disposal and cleanup of these wastes to more stringent requirements and result in increased operating costs for the Royalty Properties, as well as the oil and gas industry in general. State initiatives to further regulate the disposal of oil and gas wastes are also pending in certain states, and these initiatives could have a similar impact on the Royalty Properties.

The working interest owners have advised the Trust that they are not involved in any administrative or judicial proceedings relating to the Royalty Properties arising under federal, state or local environmental protection laws and regulations or which would have a material adverse effect on the working interest owners' financial position or results of operations.

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Item 1A. Risk Factors.

Although risk factors are described elsewhere in this Form 10-K together with specific Cautionary Statements, the following is a summary of the principal risks associated with an investment in units in the Trust.

Natural gas prices fluctuate due to a number of factors, and lower prices will reduce net proceeds available to the Trust and distributions to Trust unitholders.

The Trust's quarterly distributions are highly dependent upon the prices realized from the sale of natural gas and a material decrease in such prices could reduce the amount of Trust distributions. Natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and the working interest owners. Factors that contribute to price fluctuation include, among others:

- political conditions worldwide, in particular political disruption, war or other armed conflicts in oil producing regions;
- worldwide economic conditions;
- weather conditions;
- the supply and price of foreign natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities; and
- the effect of worldwide energy conservation measures.

Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices in the long term.

When natural gas prices decline, the Trust is affected two ways. First, net royalties are reduced. Second, exploration and development activity on the underlying properties may decline as some projects may become uneconomic and are either delayed or eliminated. The volatility of energy prices reduces the predictability of future cash distributions to unitholders. Substantially all of the natural gas and natural gas liquids produced from the Royalty Properties are being sold under short-term or multi-month contracts at market clearing prices or on the spot market.

Increased production and development costs for the Royalty will result in decreased Trust distributions.

Production and development costs attributable to the Royalty are deducted in the calculation of the Trust's share of net proceeds. Production and development costs are impacted by increases in commodity prices both directly, through commodity-price dependent costs such as electricity, and indirectly, as a result of demand-driven increases in costs of oil field goods and services. Accordingly, higher or lower production and development costs, without concurrent increases in revenues, directly decrease or increase the amount received by the Trust for the Royalty.

If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive net proceeds for those properties until future proceeds from production exceed the total of the excess costs plus accrued interest during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs.

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Trust reserve estimates depend on many assumptions that may prove to be inaccurate, which could cause both estimated reserves and estimated future revenues to be too high or too low.

The value of the units of beneficial interest of the Trust depends upon, among other things, the amount of reserves attributable to the Royalty and the estimated future value of the reserves. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures;
- the availability of enhanced recovery techniques; and
- relationships with landowners, working interest partners, pipeline companies and others.

Changes in these factors and assumptions can materially change reserve estimates and future net revenue estimates.

The reserve quantities attributable to the Royalty and revenues are based on estimates of reserves and revenues for the underlying properties. The method of allocating a portion of those reserves to the Trust is further complicated because the Trust holds an interest in the Royalty and does not own a specific percentage of the natural gas reserves. Ultimately, actual production, revenues and expenditures for the underlying properties, and therefore actual net proceeds payable to the Trust, will vary from estimates and those variations could be material. Results of drilling, testing and production after the date of those estimates may require substantial downward revisions or write-off of reserves.

The Trustee also relies entirely on reserve estimates and related information prepared by PNR and DeGoyler and McNaughton. While the Trustee has no reason to believe the reserve estimates included in this report are not accurate, to the extent additional information exists that could affect their reserve estimates, the estimated reserves in these reports could also be too low.

Operating risks for the working interest owners' interests in the Royalty Properties can adversely affect Trust distributions.

There are operational risks and hazards associated with the production and transportation of natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of natural gas, releases of other hazardous materials, mechanical failures, cratering and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, damage to the environment of natural resources, or cleanup obligations. The occurrence of drilling, production or transportation accidents and other natural disasters at any of the Royalty Properties will reduce Trust distributions by the amount of uninsured costs. These occurrences include blowouts, cratering, explosives and other environmental damage that may result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any uninsured costs would be deducted as a production cost in calculating net proceeds payable to the Trust.

Most of the gas produced in the San Juan Basin is transported on one of only two major pipelines in the area, and transportation of this gas is generally controlled by a small number of distribution

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companies. Accordingly, any disruptions to transportation lines or increases in transportation costs for production from these properties could also affect the Trust.

Terrorism and continued hostilities in the Middle East could decrease Trust distributions or the market price of the units of beneficial interest of the Trust.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism, the war in Iraq and other sustained military campaigns could adversely affect Trust distributions or the market price of the Units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in natural gas prices, or the possibility that the infrastructure on which the operators developing the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

The operators of the working interests are subject to extensive governmental regulation.

Oil and gas operations have been, and in the future will be, affected by federal, state and local laws and regulations and other political developments, such as price or gathering rate controls and environmental protection regulations. These regulations and changes in regulations could have a material adverse effect on Royalty income payable to the Trust.

Trust unitholders and the Trustee have no control over the operation or development of the Royalty Properties and have little influence over operation or development.

Neither the Trustee nor the unitholders can influence or control the operation or future development of the underlying properties. The Royalty Properties are owned by independent working interest owners. The working interest owners manage the underlying properties and handle receipt and payment of funds relating to the Royalty Properties and payments to the Trust for the Royalty. The failure of an operator to conduct its operations, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations, including environmental laws and regulations, in a proper manner could have an adverse effect on the net proceeds payable to the Trust.

The current working interest owners are under no obligation to continue operating the properties. Neither the Trustee nor the unitholders have the right to replace an operator.

The Trustee relies upon the working interests owners for information regarding the Royalty Properties.

The Trustee relies on the working interest owners for information regarding the Royalty Properties. The working interest owners control (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, effects of regulatory changes and the number of producing wells and acreage, (ii) plans for future operating and capital expenditures, (iii) geological data relating to reserves, as well as related projections regarding production, operating expenses and capital expenses used in connection with the preparation of the reserve report, (iv) forward-looking information relating to production and drilling plans and (v) information regarding the Royalty Properties responsive to litigation claims. While the Trustee requests material information for use in periodic reports as part of its disclosure controls and procedures, the Trustee does not control this information and relies entirely on the working interest owners to provide accurate and timely information when requested for use in the Trust's periodic reports.

Under the terms of the Trust Indenture, the Trustee is entitled to rely, and in fact relies, on certain experts in good faith. This reliance includes the use of an independent petroleum engineering consultant to prepare estimates of net proved reserves attributable to the Trust. This independent petroleum engineering consultant in turn relies on information provided to it by the working interest

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owners. While the Trustee has no reason to believe its reliance on experts is unreasonable, this reliance on experts and limited access to information may be viewed as a weakness as compared to the management and oversight of entity forms other than trusts.

The owner of any Royalty Property may abandon any property, terminating the related Royalty.

The working interest owners may at any time transfer all or part of the Royalty Property to another unrelated third party. Unitholders are not entitled to vote on any transfer, and the Trust will not receive any proceeds of any such transfer. Following any transfer, the Royalty Properties will continue to be subject to the Royalty, but the net proceeds from the transferred property would be calculated separately and paid by the transferee. The transferee would be responsible for all of the obligations relating to calculating, reporting and paying to the Trust the Royalty on the transferred portion of the Royalty Properties, and the current owner of the Royalty Properties would have no continuing obligation to the Trust for those properties.

The current working interest owners 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 Royalty relating to the abandoned well.

The Royalty can be sold and the Trust can be terminated.

The Trust will be terminated and the Trustee must sell the Royalty if holders of a majority of the units of beneficial interest of the Trust approve the sale or vote to terminate the Trust, or if the Trust's royalty income for each of two successive years is less than $250,000 per year. Following any such termination and liquidation, the net proceeds of any sale will be distributed to the unitholders and unitholders will receive no further distributions from the Trust. We cannot assure you that any such sale will be on terms acceptable to all unitholders.

Trust assets are depleting assets and, if the working interest owners or other operators of the Royalty Properties do not perform additional development projects, the assets may deplete faster than expected.

The net proceeds payable to the Trust are derived from the sale of depleting assets. Accordingly, the portion of the distributions to unitholders attributable to depletion may be considered a return of capital. The reduction in proved reserve quantities is a common measure of depletion. Future maintenance and development projects on the Royalty Properties will affect the quantity of proved reserves. The timing and size of these projects will depend on the market prices of natural gas. If operators of the Royalty Properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust. For federal income tax purposes, depletion is reflected as a deduction, which is dependent upon the purchase price of a unit. Please see the section entitled "Business Description of the Units Federal Income Tax Matters" under Item 1 of this Form 10-K.

Because the net proceeds payable to the Trust are derived from the sale of depleting assets, the portion of distributions to unitholders attributable to depletion may be considered a return of capital as opposed to a return on investment. Distributions that are a return of capital will ultimately diminish the depletion tax benefits available to the Trust unitholders, which could reduce the market value of the Trust units over time. Eventually, properties underlying the Trust's Royalty will cease to produce in commercial quantities and the Trust will, therefore, cease to receive any distributions of net proceeds therefrom.

Unitholders have limited voting rights.

Voting rights as a unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of unitholders or for an annual or other periodic re-election of the Trustee. Additionally, Trust unitholders have no voting rights in Pioneer or ConcoPhillips. Unlike corporations which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a corporate Trustee in accordance with the Trust Indenture and other organizational documents. The Trustee has extremely limited discretion in its administration of the Trust.

Unitholders have limited ability to enforce the Trust's rights against the current or future owners of the Royalty Properties.

The Trust Agreement and related trust law permit the Trustees and the Trust to sue the working interest owners to compel them to fulfill the terms of the Conveyance of the Royalty. If the Trustee does not take appropriate action to enforce provisions of the Conveyance, the recourse of a unitholder would likely be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. Unitholders probably would not be able to sue the working interest owners directly.

The limited liability of the Trust unitholders is uncertain.

The Trust unitholders are not protected from the liabilities of the Trust to the same extent that a shareholder would be protected from a corporation's liabilities. The structure of the Trust does not include the interposition of a limited liability entity such as a corporation or a limited partnership which would provide further limited liability protection to Trust unitholders. While the Trustee is liable for any excess liabilities incurred if the Trustee fails to insure that such liabilities are to be satisfied only out of Trust assets, under the laws of Texas, which are unsettled on this point, a holder of units may be jointly and severally liable for any liability of the Trust if the satisfaction of such liability was not contractually limited to the assets of the Trust and the assets of the Trust and the trustee are not adequate to satisfy such liability. As a result, Trust unitholders may be exposed to personal liability.

Item 1B. Unresolved Staff Comments.

There were no unresolved Securities and Exchange Commission comments as of December 31, 2007.

Item 2. Properties.

The Trust owns property interests in the Hugoton Area (Kansas) and the San Juan Basin (Northwestern New Mexico and Southwestern Coloroda). See "Buisness Description of Royalty Properties" for additional information.

Item 3. Legal Proceedings.

There are no pending legal proceedings to which the Trust is a named party. PNR has advised the Trustee that the previously reached 2006 settlement in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* filed in the 26th Judicial District Court, Stevens County, Kansas, was approved in the first quarter of 2007 by the Judge and the case was finalized in April 2007. The plaintiffs in the above noted lawsuit were royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of Pioneer Natural Resources Company ("Pioneer"). The plaintiffs sued a predecessor company to Pioneer USA asserting various claims relating to alleged improper deductions in the calculation of royalties.

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Under the terms of the agreement, Pioneer USA agreed to make cash payments to settle the plaintiffs' claims with respect to production occurring on and before December 31, 2005. Pioneer USA also agreed to adjust the manner in which royalty payments to the class members will be calculated for production occurring on and after January 1, 2006.

Pioneer's portion of the cash payment was approximately $32,700,000. Pioneer agreed to pay the cash portion in two installments. Pioneer advised the Trustee that the portion of the cash payments net to the Trust's interest was $986,138 paid on September 30, 2006 and an expected payment of approximately $900,000 was payable on September 30, 2007. The $986,138 attributable to the Trust paid on September 30, 2006, was deducted from royalty income in the fourth quarter of 2006. In October 2007, Pioneer informed the Trustee that during the course of Pioneer USA's analysis of the payments under the terms of the settlement agreement, Pioneer USA determined that the Trust should not bear any portion of the second installment payment and that Pioneer USA should reimburse the Trust for the portion of the first installment payment previously charged to the Trust and paid in September 2006. As a result, Pioneer USA included a reimbursement of $1,096,630, including interest in the amount of $110,492, to the distribution made to the Trust in October 2007 which was to be included in the Trust's fourth quarter receipts, and no portion of the second installment payment was charged to the Trust.

The Trustee has been advised by ConocoPhillips and BP Amoco that it is subject to litigation in the ordinary course of business for certain matters that include the Royalty Properties. While each of the working interest owners has advised the Trustee that it does not currently believe any of the pending litigation will have a material adverse effect net to the Trust, in the event such matters were adjudicated or settled in a material amount and charges were made against Royalty income, such charges could have a material impact on future Royalty income.

Item 4. Submission of Matters to a Vote of Security Holders.

There were no matters submitted to a vote of security holders during the fourth quarter of 2007.

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PART II

Item 5. Market for the Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.

The units of beneficial interest of the Trust are traded on the New York Stock Exchange ticker symbol "MTR". The high and low sales prices and distributions per unit for each quarter in the two years ended December 31, 2007 and December 31, 2006, were as follows:

	2007			2006		
Quarter	**High**	**Low**	**Distribution**	**High**	**Low**	**Distribution**
First	$58.94	$49.33	$ 1.3805	$69.55	$64.50	$ 1.9136
Second	$62.32	$54.77	$ 1.4225	$68.40	$60.00	$ 1.3216
Third	$65.95	$50.25	$ 1.7102	$65.90	$50.26	$ 1.0784
Fourth	$79.33	$59.13	$ 2.0452	$58.10	$48.12	$ 0.9295

At March 31, 2009, the 1,863,590 units outstanding were held by 899 unitholders of record.

Item 6. Selected Financial Data.

	2007	2006	2005	2004	2003
Royalty income	$ 12,216,271	$ 9,809,030	$ 10,568,610	$ 8,855,234	$ 9,299,034
Distributable income	$ 12,222,045	$ 9,771,034	$ 10,522,777	$ 8,814,499	$ 9,265,740
Distributable income per unit	$ 6.5583	$ 5.2431	$ 5.6465	$ 4.7298	$ 4.9720
Total assets at year end	$ 11,503,570	$ 9,834,998	$ 11,905,561	$ 11,322,309	$ 11,711,640

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following review of the Trust's financial condition and results of operations should be read in conjunction with the financial statements and notes thereto. The discussion of net production attributable to the Hugoton and San Juan properties represents production volumes that are to a large extent hypothetical as the Trust does not own and is not entitled to any specific production volumes.

Critical Accounting Policies

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income recorded for a month is the amount computed and paid by the working interest owners to the Trustee for such month rather than either the value of a portion of the oil and gas produced by the working interest owners for such month or the amount subsequently determined to be the Trust's proportionate share of the net proceeds for such month;

(b) Interest income, interest receivable and distributions payable to unitholders include interest to be earned on short-term investments from the financial statement date through the next date of distribution; and

(c) Trust general and administrative expenses, net of reimbursements, are recorded in the month they accrue.

This basis for reporting distributable income is considered to be the most meaningful because distributions to the unitholders for a month are based on net cash receipts for such month. However, these statements differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America because, under such principles, royalty income for a month would be based on net proceeds from production for such month without regard to when

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calculated or received and interest income for a month would be calculated only through the end of such month.

Liquidity and Capital Resources

As discussed under "Business Description of the Trust" in Item 1 of this Form 10-K, the Trust's source of cash is the Royalty income received from its share of the net proceeds from the Royalty Properties. Reference is made to the Notes to Financial Statements under Item 8 of this Form 10-K for estimates of future Royalty income attributable to the Royalty.

In accordance with the provisions of the Conveyance, generally all revenues received by the Trust, net of Trust administrative expenses and the amount of established reserves, are distributed currently to the unitholders.

During 2008, the Trustee engaged an independent consulting firm to audit revenues, expenses and established reserves of certain working interest owners. This review and audit remains ongoing. While this audit has highlighted issues that remain open, the Trustee has not determined at this time whether any audit exceptions will result in any material gains or expenses net to the Trust.

Financial Review

Years 2007 and 2006

	Years Ended December 31,	
	2007	**2006**
Royalty income	$ 12,216,271	$ 9,809,030
Interest income	97,278	30,275
General and administrative expenses	(91,504)	(68,271)
Distributable income	$ 12,222,045	$ 9,771,034
Distributable income per unit	$ 6.5583	$ 5.2431

The Trust's Royalty income was $12,216,271 in 2007, an increase of approximately 25% as compared to $9,809,030 in 2006, primarily as a result of decreased capital spending in 2007.

Hugoton Field

Royalty income attributable to the Hugoton Royalty Properties was $5,705,773 in 2007, an increase of approximately 19%, as compared to $4,810,684 million in 2006, primarily as a result of payments and interest recieved during 2007 of approximately $1,100,000 to partially settle claims made in the *John Steven Alford and Robert Larrabee v. Pioneer* lawsuit discussed in Item 3. "Legal Proceedings" of this Form 10-K.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $6.07 per Mcf and $42.85 per barrel, respectively, in 2007 as compared to $7.48 per Mcf and $42.83 per barrel, respectively, in 2006. Net production attributable to the Hugoton Royalty was 543,241 Mcf of natural gas and 30,625 barrels of natural gas liquids in 2007 as compared with 406,409 Mcf of natural gas and 41,344 barrels of natural gas liquids in 2006. Actual production volumes attributable to the Hugoton properties were 759,786 Mcf of natural gas and 36,660 barrels of natural gas liquids in 2007 as compared with 739,168 Mcf of natural gas and 41,363 barrels of natural gas liquids in 2006. The increase in gas production and the decrease in the natural gas liquids production for the year ended December 31, 2007 compared to the same period in 2006 was primarily due to the nitrogen injection unit being shut-down for a portion of January and February in 2007. The shut-down of the nitrogen injection unit increased gas production while it decreased natural gas liquids production.

The Hugoton capital expenditures were $144,559 for 2007, a decrease of approximately 33% as compared to $217,304 for 2006. The decrease in the capital expenditures was primarily due to less wells drilled in 2007 as compared to 2006. Operating costs were $1,422,455 during 2007, an increase of approximately 11% as compared to $1,285,962 during 2006 due to increases in production taxes, well workers, and higher rates charged by service providers.

San Juan Basin

Royalty income from the San Juan Basin Royalty properties is calculated and paid to the Trust on a state-by-state basis. Royalty income from the San Juan Basin Royalty Properties located in the state of New Mexico was $5,316,376 in 2007 as compared to $4,019,997 in 2006, an increase of 33%. The increase in Royalty income was due primarily to increased natural gas liquid production and decreased operating expenditures in the first nine months of 2006 from the San Juan Basin-New Mexico properties. Net production attributable to the San Juan Basin Royalty located in the state of New Mexico was 578,316 Mcf of natural gas and 56,188 barrels of natural gas liquids, oil and condensate in 2007 as compared to 374,180 Mcf of natural gas and 40,567 barrels of natural gas liquids, oil and condensate in 2006. Actual production volumes attributable to the San Juan Basin properties located in the state of New Mexico was 941,366 Mcf of natural gas and 73,888 barrels of natural gas liquids, oil and condensate in 2007 as compared with 928,364 Mcf of natural gas and 48,046 barrels of natural gas liquids, oil and condensate in 2006. The increase in production volume for the year ended December 31, 2007 compared to the same period 2006 was due to the better run times on conventional gathering. The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty properties located in the state of New Mexico was $5.36 per Mcf and $39.45 per barrel, respectively, in 2007 compared with $6.37 per Mcf and $40.34 per barrel, respectively, in 2006.

San Juan-New Mexico capital expenditures were $1,007,366 during 2007, an increase of approximately 49% as compared to $678,351 during 2006. Operating costs were $1,638,835 during 2007, a decrease of approximately 17% as compared to $1,966,468 during 2006. The decrease in operating costs during 2007 compared to 2006 was due to inclement weather that impacted the operations coupled with a reduction in lease inspections, facilities expenses and well workover expenses.

The costs related to the San Juan Basin, Colorado portion were recovered in December 2004. However, subsequent earnings were not remitted to the Trust until December 2006 and July 2007. The cumulative earnings, including interest on undistributed earnings, reported to the Trust by the working interest owner through November 2006, totaled $1,280,412. In December 2006, BP remitted $978,349 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings related to the properties it operates. In July 2007, Red Willow remitted $159,497 for payment of undistributed earnings from January 2005 through December 2006 for the San Juan Basin-Colorado Royalty properties it operates. BP communicated to the Trust these distributions represent all of the previously unpaid revenues. The Trustee is currently investigating the $142,566 difference in the original estimate of unpaid proceeds of $1,280,412 and the payment of $1,137,846. Since Royalty income for the Trust is recorded on a cash basis, the earnings for the year ended December 31, 2006 were not recognized as income until the quarter ended December 31, 2006 and September 30, 2007.

Royalty income from the San Juan Basin Colorado Royalty Properties was $1,194,122 in 2007 as compared to $978,349 in 2006. Net production attributable to the San Juan Basin Royalty properties primarily located in Colorado were 194,775 Mcf of natural gas in 2007 as compared to 223,367 Mcf of natural gas in 2006. The average price received for natural gas from these San Juan Basin properties was $5.99 per Mcf in 2007 as compared with $4.38 per Mcf in 2006. Actual natural gas production

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volumes attributable to the San Juan Basin Colorado Properties were 177,619 Mcf in 2007. Net production of natural gas liquids, oil and condensate from the San Juan Basin Colorado Properties in 2007 was 734 barrels and actual production was 1,348 barrel in 2007. The average price received for natural gas liquids, oil and condensate from the San Juan Basin Colorado properties was $37.34 per barrel in 2007. Operating costs for the San Juan Basin properties was $136,772 in 2007 as compared to $270,017 in 2006.

Years 2006 and 2005

	Years Ended December 31,	
	2006	**2005**
Royalty income	$9,809,030	$10,568,610
Interest income	30,275	17,780
General and administrative expenses	(68,271)	(63,613)
Distributable income	$9,771,034	$10,522,777
Distributable income per unit	$ 5.2431	$ 5.6465

The Trust's Royalty income was $9,809,030 in 2006, a decrease of approximately 7% as compared to $10,568,610 in 2005, primarily as a result of increased capital spending in 2006.

Royalty income from the Hugoton Royalty Properties was $4,810,684 in 2006, a decrease of approximately 12%, as compared to $5,441,802 million in 2005, primarily as a result of payments made of approximately $1,000,000 to partially settle claims made in the *John Steven Alford and Robert Larrabee v. Pioneer* lawsuit discussed in Item 3. "Legal Proceedings" of this Form 10-K.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $7.48 per Mcf and $42.83 per barrel, respectively, in 2006 as compared to $6.62 per Mcf and $34.44 per barrel, respectively, in 2005. Net production attributable to the Hugoton Royalty was 406,409 Mcf of natural gas and 41,344 barrels of natural gas liquids in 2006 as compared with 591,015 Mcf of natural gas and 44,404 barrels of natural gas liquids in 2005. Actual production volumes attributable to the Hugoton properties were 739,168 Mcf of natural gas and 41,363 barrels of natural gas liquids in 2006 as compared with 786,935 Mcf of natural gas and 44,425 barrels of natural gas liquids in 2005.

Royalty income from the San Juan Basin Royalty properties is calculated and paid to the Trust on a state-by-state basis. Royalty income from the San Juan Basin Royalty Properties located in the state of New Mexico was $4,019,997 in 2006 as compared to $5,126,808 in 2005, a decrease of 22%. The decrease in Royalty income was due to decreased natural gas and natural gas liquids volumes in 2006 as well as, increased capital expenditures. Royalty income from the San Juan Basin Properties located in the state of Colorado was $978,349 in 2006 as compared to $0 in 2005. The San Juan Basin Royalty Properties located in the state of Colorado recouped all costs related to the Fruitland Coal drilling program as of December 2004. However, subsequent earnings were not remitted to the Trust until December 2006. The cumulative earnings, including interest on undistributed earnings, reported to the Trust by BP through November 2006, totaled approximately $1,280,000. In December, BP remitted approximately $978,000 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings. The working interest owner communicated to the Trust this distribution represents all of the previously unpaid revenues. The Trustee is currently investigating the $251,000 difference in the original estimate of unpaid proceeds of approximately $1,229,000 and the payment of approximately $978,000.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty properties located in the state of New Mexico was $6.37 per Mcf and

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$40.34 per barrel, respectively, in 2006 compared with $6.24 per Mcf and $34.37 per barrel, respectively, in 2005. Net production attributable to the San Juan Basin Royalty located in the state of New Mexico was 374,180 Mcf of natural gas and 40,567 barrels of natural gas liquids, oil and condensate in 2006 as compared to 589,652 Mcf of natural gas and 42,112 barrels of natural gas liquids, oil and condensate in 2005. Actual production volumes attributable to the San Juan Basin properties located in the state of New Mexico was 928,364 Mcf of natural gas and 48,046 barrels of natural gas liquids, oil and condensate in 2006 as compared with 1,038,065 Mcf of natural gas and 51,331 barrels of natural gas liquids, oil and condensate in 2005.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty properties located in the state of Colorado was $4.38 per Mcf in 2006. Net production attributable to the San Juan Basin Royalty properties located in the state of Colorado was 223,367 Mcf of natural gas in 2006. As described above, there were no earnings remitted to the Trust in 2005 related to the San Juan Royalty properties located in the State of Colorado.

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SUMMARY OF ROYALTY INCOME, PRODUCTION AND AVERAGE PRICES (Unaudited)

	Hugoton		San Juan New Mexico		San Juan Colorado		Total	
	Natural Gas	Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids
Year ended December 31, 2007:								
The Trust's proportionate share of Gross Proceeds(1)	$ 5,702,879	$ 1,569,899	$ 5,047,932	$ 2,914,645	$ 1,309,166	$ 28,771	$ 12,059,977	$ 4,513,315
Less the Trust's proportionate share of								
Capital costs	(107,490)	(37,065)	(714,876)	(292,490)	(6,939)	(104)	(829,305)	(329,659)
Operating costs	(1,201,906)	(220,544)	(1,233,284)	(405,551)	(135,524)	(1,248)	(2,570,714)	(627,343)
Royalty Income	$ 4,393,483	$ 1,312,290	$ 3,099,772	$ 2,216,604	$ 1,166,703	$ 27,419	$ 8,659,958	$ 3,556,313
Average Sales Price	$ 6.07	$ 42.85	$ 5.36	$ 39.45	$ 5.99	$ 37.36	$ 6.62	$ 40.62
Net production volumes attributable to the Royalty paid(3)	(Mcf 543,241)	(Bbls 30,625)	(Mcf 578,316)	(Bbls 56,188)	(Mcf 194,775)	(Bbls 734)	(Mcf 1,316,332)	(Bbls 87,547)
Year ended December 31, 2006:								
The Trust's proportionate share of Gross Proceeds(1)	$ 5,527,968	$ 1,770,745	$ 5,915,794	$ 1,937,941	$ 1,550,429	$	$ 12,994,191	$ 3,708,686
Less the Trust's proportionate share of								
Capital costs	(217,180)		(1,205,870)				(1,423,050)	
Operating costs	(2,270,849)		(2,326,396)	(301,472)	(270,017)		(4,867,262)	(301,472)
Withheld revenues(2)					(302,063)		(302,063)	
Royalty Income	$ 3,039,939	$ 1,770,745	$ 2,383,528	$ 1,636,469	$ 978,349	$	$ 6,401,816	$ 3,407,214
Average Sales Price	$ 7.48	$ 42.83	$ 6.37	$ 40.34	$ 4.38	$	$ 6.38	$ 41.58
Net production volumes attributable to the Royalty paid(3)	(Mcf 406,409)	(Bbls 41,344)	(Mcf 374,180)	(Bbls 40,567)	(Mcf 223,367)	(Bbls)	(Mcf 1,003,956)	(Bbls 81,911)
Year ended December 31, 2005:								
The Trust's proportionate share of Gross Proceeds(1)	$ 5,203,899	$ 1,529,284	$ 7,388,469	$ 1,764,397	$	$	$ 12,592,368	$ 3,293,681
Less the Trust's proportionate share of								
Capital costs	(160,042)		(693,556)				(853,598)	
Operating costs	(1,131,339)		(2,471,497)	(317,016)			(3,602,836)	(317,016)
Withheld revenues(2)			(543,989)				(543,989)	
Royalty Income	$ 3,912,518	$ 1,529,284	$ 3,679,427	$ 1,447,381	$	$	$ 7,591,945	$ 2,976,665
Average Sales Price	$ 6.62	$ 34.44	$ 6.24	$ 34.37	$	$	$ 6.43	$ 34.41
Net production volumes attributable to the Royalty paid(3)	(Mcf 591,015)	(Bbls 44,404)	(Mcf 589,652)	(Bbls 42,112)	(Mcf)	(Bbls)	(Mcf 1,180,707)	(Bbls 86,506)

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(1)

Gross Proceeds from natural gas liquids attributable to the Hugoton and San Juan Basin Properties are net of a volumetric in-kind processing fee retained by PNR and ConocoPhillips, respectively.

(2)

The Colorado portion of the San Juan Basin Royalty properties recouped all costs related to the Fruitland Coal drilling program as of December 2004. However, subsequent cumulative earnings were not remitted to the Trust until December 2006 and July 2007. The cumulative earnings reported to the Trust by the Working Interest Owner from January 2005 through October 2006 totaled approximately $1,280,000. In December 2006, BP as operator of a portion of the San Juan Basin-Colorado Royalty properties remitted approximately $978,000 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings. In the quarter ended September 30, 2007, Red Willow remitted $226,000 to the Trust relating to San Juan Basin-Colorado Royalty properties that it operates. Of the $226,000 remitted by Red Willow, $66,000 relates to production during the three and nine months ended September 30, 2007. The remaining $159,000 relate to undistributed earnings from January 2005 through December 2006. Since Royalty income for the Trust is recorded on a cash basis, Royalty income for year ended December 31, 2005 and 2004 of $543,989 and $38,860, respectively, was not recognized until the year ended December 31, 2006.

Royalty income reported from BP is net of pre-main line production costs. These costs were charged to the Trust in error and as a result royalty income for previous periods were reduced. Because royalty income recorded for a month is the amount computed and paid by BP, the additional royalties, if any, will not be recorded until received.

(3)

Net production volumes attributable to the Royalty are determined by dividing Royalty income by the average sales price received. Net production volumes attributable for Hugoton Royalty for 2007 were not calculated for the 2007 reimbursement from PNR related to the *Alford* settlement.

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Off-Balance Sheet Arrangements

None.

Contractual Obilgations

None.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Not applicable.

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Item 8. Financial Statements and Supplementary Data.

MESA ROYALTY TRUST
STATEMENTS OF DISTRIBUTABLE INCOME

	Years Ended December 31,		
	2007	**2006**	**2005**
Royalty income	$ 12,216,271	$ 9,809,030	$ 10,568,610
Interest income	97,278	30,275	17,780
General and administrative expenses	(91,504)	(68,271)	(63,613)
Distributable income	$ 12,222,045	$ 9,771,034	$ 10,522,777
Distributable income per unit	$ 6.5583	$ 5.2431	$ 5.6465

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31,	
	2007	**2006**
ASSETS		
Cash and short-term investments	$ 3,783,453	$ 1,725,732
Interest receivable	27,904	6,551
Net overriding royalty interests in oil and gas properties	42,498,034	42,498,034
Less: accumulated amortization	(34,805,821)	(34,395,319)
Total assets	$ 11,503,570	$ 9,834,998
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 3,811,357	$ 1,732,283
Trust corpus (1,863,590 units of beneficial interest authorized and outstanding)	7,692,213	8,102,715
Total liabilities and trust corpus	$ 11,503,570	$ 9,834,998

STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31,		
	2007	**2006**	**2005**
Trust corpus, beginning of year	$ 8,102,715	$ 8,521,268	$ 9,017,067
Distributable income	12,222,045	9,771,034	10,522,777
Distributions to unitholders	(12,222,045)	(9,771,034)	(10,522,777)
Amortization of net overriding royalty interests	(410,502)	(418,553)	(495,799)
Trust corpus, end of year	$ 7,692,213	$ 8,102,715	$ 8,521,268

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

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS

(1) Trust Organization and Provisions

The Mesa Royalty Trust (the "Trust") was created on November 1, 1979. On that date, Mesa Petroleum Co., predecessor to Mesa Limited Partnership ("MLP") which was the predecessor to MESA Inc., conveyed to the Trust an overriding royalty interest (the "Royalty") equal to 90% of the Net Proceeds (as defined in the Conveyance and described below) attributable to the specified interests in properties conveyed by the assignor on that date (the "Subject Interests"). The Subject Interests consisted of interests in certain producing oil and gas properties located in the Hugoton field of Kansas, the San Juan Basin field of New Mexico and Colorado and the Yellow Creek field of Wyoming (the "Royalty Properties"). The Royalty is evidenced by counterparts of an Overriding Royalty Conveyance dated as of November 1, 1979 (the "Conveyance"). On April 30, 1991, MLP sold its interests in the Royalty Properties located in San Juan Basin field to ConocoPhillips. ConocoPhillips sold the portion of its interests in the San Juan Basin Royalty Properties located in Colorado to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP Amoco Company ("BP") a subsidiary of BP p.l.c. Until August 7, 1997, MESA Inc. operated the Hugoton Royalty Properties through Mesa Operating Co., a wholly owned subsidiary of MESA Inc. On August 7, 1997, MESA Inc. merged with and into Pioneer Natural Resources Company ("Pioneer"), formerly a wholly owned subsidiary of MESA Inc., and Parker & Parsley Petroleum Company merged with and into Pioneer Natural Resources USA, Inc. (successor to Mesa Operating Co.), a wholly owned subsidiary of Pioneer ("PNR") (collectively, the mergers are referred to herein as the "Merger"). Subsequent to the Merger, the Hugoton Royalty Properties have been operated by PNR. The San Juan Basin Royalty Properties located in New Mexico are operated by ConocoPhillips. The San Juan Basin Royalty Properties located in Colorado are operated by BP. As used in the notes to financial statements, PNR refers to the operator of the Hugoton Royalty Properties, ConocoPhillips refers to the operator of the San Juan Basin Royalty Properties, other than the portion of such properties located in Colorado, and BP refers to the operator of the Colorado San Juan Basin Royalty Properties unless otherwise indicated.

Effective October 2, 2006, the Bank of New York Trust Company, N.A. (the "Trustee") succeeded JPMorgan Chase Bank, N.A. as Trustee of the Trust. JPMorgan Chase Bank, N.A. is the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association. The terms of the Mesa Royalty Trust Indenture (the "Trust Indenture") provide, among other things, that:

(a) the Trust cannot engage in any business or investment activity or purchase any assets;

(b) the Royalty can be sold in part or in total for cash upon approval of the unitholders;

(c) the Trustee can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of the borrowings;

(d) the Trustee will make cash distributions to the unitholders in January, April, July and October each year as discussed more fully in Note 4;

(e) the Trust will terminate upon the first to occur of the following events: (i) at such time as the Trust's royalty income for each of two successive years is less than $250,000 per year or (ii) a vote by the unitholders in favor of termination. Upon termination of the Trust, the Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to unitholders of any funds remaining after all Trust liabilities have been satisfied; and

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(1) Trust Organization and Provisions (Continued)

(f) PNR, ConocoPhillips, and BP (collectively the "Working Interest Owners") will reimburse the Trust for 59.34%, 27.45% and 1.77% respectively, for general and administrative expenses of the Trust.

(2) Net Overriding Royalty Interest

In accordance with the Conveyance, the Working Interest Owners are obligated to calculate and pay the Trust each month the Royalty which is equal to 90% of the Net Proceeds (as defined in the Conveyance) attributable to the month. In 1985, the Trust Indenture was amended and the Trust conveyed to an affiliate of Mesa Petroleum Co. 88.5571% of the original Royalty (such transfer, the "1985 Assigment"). The effect of the assignment was an overall reduction of approximately 88.56% in the size of the Trust. As a result, the Trust is now entitled to receive 11.44% of 90% of the Net Proceeds attributable to each month.

Amortization of the Royalty is computed on a unit-of-production basis and is charged directly to trust corpus since such amount does not affect distributable income.

(3) Basis of Accounting

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income recorded for a month is the amount computed and paid by the working interest owners to the Trustee for such month rather than either the value of a portion of the oil and gas produced by the working interest owners for such month or the amount subsequently determined to be the Trust's proportionate share of the net proceeds for such month;

(b) Interest income, interest receivable and distributions payable to unitholders include interest to be earned on short-term investments from the financial statement date through the next date of distribution; and

(c) Trust general and administrative expenses, net of reimbursements, are recorded in the month they accrue.

This basis for reporting distributable income is considered to be the most meaningful because distributions to the unitholders for a month are based on net cash receipts for such month. However, these statements differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America because, under such principles, royalty income for a month would be based on net proceeds from production for such month without regard to when calculated or received and interest income for a month would be calculated only through the end of such month.

(4) Distributions to Unitholders

Under the terms of the Trust Indenture, the Trustee must distribute to the unitholders all cash receipts, after paying liabilities and providing for cash reserves as determined necessary by the Trustee. The amounts distributed are determined on a monthly basis and are payable to unitholders of record as of the last business day of each month. However, cash distributions are made quarterly in January, April, July and October, and include interest earned from the monthly record dates to the date of the distribution.

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(5) Federal Income Taxes

In a technical advice memorandum dated February 26, 1982, the IRS advised the Dallas District Director that the Trust is classifiable as a grantor trust and not as an association taxable as a corporation. As a grantor trust, the Trust will incur no federal income tax liability.

(6) PNR Legal Proceedings

There are no pending legal proceedings to which the Trust is a named party. PNR has advised the Trustee that the previously reached 2006 settlement in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* filed in the 26th Judicial District Court, Stevens County, Kansas, was approved in the first quarter of 2007 by the Judge and the case was finalized in April 2007. The plaintiffs in the above noted lawsuit were royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of Pioneer Natural Resources Company ("Pioneer"). The plaintiffs sued a predecessor company to Pioneer USA asserting various claims relating to alleged improper deductions in the calculation of royalties.

Under the terms of the agreement, Pioneer USA agreed to make cash payments to settle the plaintiffs' claims with respect to production occurring on and before December 31, 2005. Pioneer USA also agreed to adjust the manner in which royalty payments to the class members will be calculated for production occurring on and after January 1, 2006.

Pioneer's portion of the cash payment is approximately $32,700,000. Pioneer agreed to pay the cash portion in two installments. Pioneer advised the Trustee that the portion of the cash payments net to the Trust's interest was approximately $1,000,000 paid on September 30, 2006 and an expected payment of $986,138 payable on September 30, 2007. The $986,138 attributable to the Trust paid on September 30, 2006, was deducted from royalty income in the fourth quarter of 2006. In October 2007, Pioneer informed the Trustee that during the course of Pioneer USA's analysis of the payments under the terms of the settlement agreement, Pioneer USA determined that the Trust should not bear any portion of the second installment payment and that Pioneer USA should reimburse the Trust for the portion of the first installment payment previously charged to the Trust and paid in September 2006. As a result, Pioneer USA included a reimbursement of $1,096,630, including interest in the amount of $110,492, to the distribution made to the Trust in October 2007 to be included in the Trust's fourth quarter receipts, and no portion of the second installment payment was charged to the Trust.

(7) Supplemental Reserve Information (Unaudited)

Estimates of the proved oil and gas reserves attributable to the Hugoton Royalty Properties as of December 31, 2007, 2006 and 2005 are based on reports prepared by PNR. The estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission (the "SEC"). Accordingly, the estimates were based on existing economic and operating conditions. The reserve volumes and revenue values for the Trust's Royalty were estimated by allocating to the Trust a portion of the estimated combined net reserve volumes of the Hugoton Royalty Properties based on future net revenue. Production volumes are allocated based solely on royalty income. Because the net reserve volumes attributable to the Trust's Royalty interest are estimated using an allocation of reserve volumes based on estimates of future net revenue, a change in prices or costs will result in changes in the estimated net reserve volumes. Therefore, the estimated net reserve volumes attributable to the Trust's Royalty will vary if different future price and cost assumptions are used. Only costs necessary to

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(7) Supplemental Reserve Information (Unaudited) (Continued)

develop and produce existing proved reserve volumes were assumed in the allocation of reserve volumes to the Royalty.

Estimates of proved oil and gas reserves attributable to the New Mexico and Colorado portions of the San Juan Basin Royalty Properties are based on a reserve report prepared by DeGoyler & MacNaughton, independent petroleum engineering consultants, as of December 31, 2007.

Future prices for natural gas and oil, condensate and natural gas liquids were based on prices at each year end. Operating costs, production and ad valorem taxes and future development and abandonment costs were based on current costs as of each year end, with no escalation.

There are numerous uncertainties inherent in estimating the quantities and value of proved reserves and in projecting the future rates of production and timing of expenditures. The reserve data below represent estimates only and should not be construed as being exact. Moreover, the discounted values should not be construed as representative of the current market value of the Royalty. A market value determination would include many additional factors including: (i) anticipated future oil and gas prices; (ii) the effect of federal income taxes, if any, on the future royalties; (iii) an allowance for return on investment; (iv) the effect of governmental legislation; (v) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities; and (vi) other business risks.

Estimates of reserve volumes attributable to the Royalty are shown in order to comply with requirements of the SEC. There is no precise method of allocating estimates of physical quantities of reserve volumes between the Working Interest Owners and the Trust, since the Royalty is not a working interest and the Trust does not own and is not entitled to receive any specific volume of reserves from the Royalty. The quantities of reserves attributable to the Trust have been and will be affected by changes in various economic factors utilized in estimating net revenues from the Royalty Properties. Therefore, the estimates of reserve volumes set forth below are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest.

The following schedules set forth (i) the estimated net quantities of proved and proved developed oil, condensate and natural gas liquids and natural gas reserves attributable to the Royalty, and (ii) the standardized measure of the discounted future royalty income attributable to the Royalty and the nature of changes in such standardized measure between years. These schedules are prepared on the accrual basis, which is the basis on which the Working Interest Owners maintain their production records and is different from the basis on which the Royalty is computed.

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

ESTIMATED QUANTITIES OF PROVED AND PROVED DEVELOPED RESERVES (Unaudited)

	Oil, Condensate and Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Reserves:		
December 31, 2004	2,411,194	29,166,694
Revisions to previous estimates	36,322	2,685,788
Extensions, discoveries and other additions		
Production	(86,516)	(1,180,667)
December 31, 2005	2,361,000	30,671,815
Revisions to previous estimates	260,345	3,896,093
Extensions, discoveries and other additions		
Production	(81,949)	(1,003,957)
December 31, 2006	2,539,396	33,563,951
Revisions to previous estimates	(1,538,328)	(14,856,500)
Extensions, discoveries and other additions		
Production	(91,356)	(1,285,368)
December 31, 2007	909,712	17,422,083
Proved Developed Reserves:		
December 31, 2004	2,346,194	28,501,694
December 31, 2005	2,361,000	29,961,815
December 31, 2006	2,531,396	32,229,951
December 31, 2007	909,712	17,422,083

The Hugoton Royalty represents 47%, 15%, and 23% of the estimated proved oil, condensate and natural gas liquids reserves and 41%, 31%, and 31% of the estimated proved natural gas reserves as of December 31 of 2007, 2006 and 2005, respectively.

The December 31, 2007 reserve estimates for the San Juan Basin properties were prepared by a third party reservoir engineering firm, whereas the December 31, 2006 and 2005 reserve estimates were prepared by the Working Interest Owner. Revisions to previous estimate in 2007 are primarily due to professional differences in judgment regarding estimate of San Juan Basin reserves.

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

STANDARDIZED MEASURE OF FUTURE ROYALTY INCOME FROM PROVED OIL AND GAS RESERVES, DISCOUNTED AT 10% PER ANNUM (Unaudited)

	December 31, 2007	2006	2005
	(In thousands)		
The Trust's proportionate share of future gross proceeds	$ 180,349	$ 277,063	$ 456,388
Less the Trust's proportionate share of Future operating costs	(26,053)	(59,343)	(131,976)
Future capital costs	(191)	(7,268)	(2,983)
Future royalty income	154,105	210,452	321,429
Discount at 10% per annum	(80,353)	(129,366)	(195,407)
Standardized measure of future royalty income from proved oil and gas reserves	$ 73,752	$ 81,086	$ 126,022

CHANGES IN THE STANDARDIZED MEASURE OF FUTURE ROYALTY INCOME FROM PROVED OIL AND GAS RESERVES, DISCOUNTED AT 10% PER ANNUM (Unaudited)

	December 31, 2007	2006	2005
	(In thousands)		
Standardized measure at beginning of year	$ 81,086	$ 126,022	$ 92,129
Revisions of previous estimates	(35,821)	1,033	(2,214)
Net changes in price and production costs	32,594	(48,762)	37,462
Extensions, discoveries and other additions			
Royalty income	(12,216)	(9,809)	(10,568)
Accretion of discount	8,109	12,602	9,213
Net changes in standardized measure	(7,334)	(44,936)	33,893
Standardized measure at end of year	$ 73,752	$ 81,086	$ 126,022

The Hugoton Royalty represents approximately 46% and 47% of the standardized measure of future royalty income for 2007 and 2006, respectively.

Standardized measure at December 31, 2007 was calculated using natural gas prices of $6.00 per Mcf for Hugoton properties and $5.48 per Mcf for San Juan properties.

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Selected Quarterly Financial Data (Unaudited)

	Summarized Quarterly Results Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
2007:				
Royalty income	$ 2,563,081	$ 2,662,923	$ 3,180,214	$ 3,810,053
Distributable income	$ 2,572,645	$ 2,651,008	$ 3,187,035	$ 3,811,357
Distributable income per unit	$ 1.3805	$ 1.4225	$ 1.7102	$ 2.0452
2006:				
Royalty income	$ 3,580,350	$ 2,472,887	$ 2,022,637	$ 1,733,156
Distributable income	$ 3,566,247	$ 2,462,899	$ 2,009,605	$ 1,732,283
Distributable income per unit	$ 1.9136	$ 1.3216	$ 1.0784	$ 0.9295

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

**The Bank of New York Trust Company, N.A., Trustee
and the Unit Holders of Mesa Royalty Trust:**

We have audited the accompanying statements of assets, liabilities and trust corpus of Mesa Royalty Trust as of December 31, 2007 and 2006, and the related statements of distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2007. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

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

As described in Note 3, these financial statements were prepared on the basis of cash receipts and disbursements as prescribed by the Securities and Exchange Commission, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of Mesa Royalty Trust as of December 31, 2007 and 2006, and the distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2007, in conformity with the basis of accounting described in Note 3.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Mesa Royalty Trust's internal control over financial reporting as of December 31, 2007, based on criteria established in "*Internal Control Integrated Framework*" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated April 3, 2009 expressed an unqualified opinion on the effectiveness of the Trust's internal control over financial reporting.

KPMG LLP

Houston, Texas
April 3, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Bank of New York Tust Company, N.A., Trustee
and the Unit Holders of Mesa Royalty Trust

We have audited Mesa Royalty Trust's (the "Trust") internal control over financial reporting as of December 31, 2007, based on criteria established in "*Internal Control Integrated Framework*" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trustee is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

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

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

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

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