MESA ROYALTY TRUST/TX
Form 10-K405
March 27, 2001

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(MARK ONE)

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2000

OR

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM ______________ TO ______________

COMMISSION FILE NUMBER 1-7884

MESA ROYALTY TRUST

(Exact Name of Registrant as Specified in Its Charter)

NEW YORK	74-6284806
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
THE CHASE MANHATTAN BANK, INSTITUTIONAL TRUST SERVICES 712 MAIN STREET HOUSTON, TEXAS	
(Address of Principal Executive Offices)	77002 (Zip Code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE: 1-800-852-1422

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 whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes /X/ No / /

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

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 March 23, 2001, of $56.00 was approximately $104,361,040.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of March 23, 2001, 1,863,590 Units of Beneficial Interest 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. 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.

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 Chase Manhattan Bank (the "Trustee"), 712 Main Street, Houston, Texas 77002. The telephone number of the Trust is 1-800-852-1422.

The Trust was created on November 1, 1979 when Mesa Petroleum Co. conveyed to the Trust a 90% net profits overriding royalty interest (the "Royalty") 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 (collectively, the "Royalty Properties"). 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 Conoco Inc. ("Conoco"). Conoco 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 Amoco Production Company ("Amoco"), a subsidiary of BP Amoco. 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 Conoco. Substantially all of the San Juan Basin Royalty Properties located in Colorado are operated by Amoco. As used in this report, PNR refers to the operator of the Hugoton Royalty Properties, Conoco refers to the operator of the New Mexico San Juan Basin Royalty Properties and Amoco 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 $7,960,109 and $5,475,497 for the years 2000 and 1999, 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 instrument conveying the Royalty to the Trust (the "Conveyance"), the Trust is entitled to a percentage of the Net Proceeds, as hereinafter defined, realized from the minerals 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" means the excess of Gross Proceeds, as hereinafter defined, received by the working interest owners during a particular period over operating and capital costs for such period. "Gross Proceeds" means the amount received by the

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working interest owners from the sale of minerals covered by the Royalty, subject to certain adjustments. 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. The effect of the amendment was an overall reduction of approximately 89% 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.

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 23, 2001.

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 Chase Manhattan Bank or the interest rate which The Chase Manhattan Bank pays in the normal course of business on amounts placed with it, whichever is greater.

LIABILITY OF UNITHOLDERS

As regards 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

In a technical advice memorandum dated February 26, 1982, the National Office of the Internal Revenue Service ("IRS") advised the Dallas District Director that the Trust is classifiable as a grantor trust and not as an association taxable as a corporation.

INCOME AND DEPLETION

Royalty income, net of depletion and severance taxes, is treated as portfolio income, and subject to certain exceptions and transitional rules, royalty income cannot be offset by losses from passive businesses. 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 that 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.

SECTION 29 CREDIT

The Trust receives royalty payments attributable to coal seam gas production from the Fruitland Coal Formation properties. Thus, unitholders are potentially eligible to claim their share of the tax credit attributable to this qualifying production. Each unitholder should consult his tax advisor regarding the limitations and requirements for claiming this tax credit.

BACKUP WITHHOLDING

Distributions from the Trust are generally subject to backup withholding at a rate of 31% of these distributions. Backup withholding will not normally apply to distributions to a unitholder, however, unless a 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 a 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 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 to the extent of the intangible drilling and development costs incurred with respect to the property and depletion claimed with respect to such property 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 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 exceeded one year as of the date of sale or exchange. A long-term capital gains rate of 20% applies to most capital assets sold with a holding period of more than one year. Capital gain or loss will be short-term if the unit has not been held for more than one year at the time of disposition.

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 produced by the Royalty at a rate equal to 30% or lower treaty rate, if applicable. 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 Internal Revenue Code of 1986, as amended 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 Internal Revenue 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 owning greater than five percent of the outstanding units are subject to United States federal income tax on the gain on the disposition of their units. Non-U.S. unitholders owning less than five percent of the outstanding units are not 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 other considerations. Therefore, each non-U.S. unitholder should consult with his own tax adviser as to the advisability of his ownership of units.

TAX-EXEMPT ORGANIZATIONS

Investments in publicly traded partnerships are treated the same as investments in other partnerships for purposes of the rules governing unrelated business taxable income. 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 income. Tax-exempt unitholders should consult their own advisors with respect to the treatment of royalty income.

DESCRIPTION OF ROYALTY PROPERTIES

PRODUCING ACREAGE AND WELLS AS OF DECEMBER 31, 2000

	PRODUCING ACRES(1)		PRODUCING WELLS(1)(	
	GROSS	NET	OIL	
Hugoton Area (Kansas)......................................	103,364	103,114	466	4
San Juan Basin (Northwestern New Mexico and Southwestern Colorado)..	40,716	31,328	1,561	4
Total...	144,080	134,442	2,027	9

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(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".

(2) One or more completions in the same bore hole are counted as one well. Where multiple well bores are in a single production unit, the unit is counted as one well.

HUGOTON

The principal property interest conveyed to the Trust accounts for approximately 46% 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 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 Conoco on April 30, 1991. Conoco subsequently sold its underlying interest in 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 Amoco. See "Description of the Trust". The San Juan Basin Royalty Properties located in Colorado account for less than 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, 2000, 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 in the unit, 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 $18.4 million. The Trust's share of the total expenditures was approximately $2.4 million. 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 have been made since 1990, as the costs of the Fruitland Coal drilling in Colorado have not yet been recovered. The San Juan Basin development drilling program had no effect on Royalty income or distributions relating to the Hugoton Royalty.

Conoco has informed the Trust that it believes the production from the Fruitland Coal formation will generally qualify for the tax credits provided under Section 29 of the Code. See "Description of the Units--Federal Income Tax Matters--Section 29 Credit."

RESERVES

A study of the proved oil and gas reserves attributable to the Hugoton Royalty as of December 31, 2000 have been made by PNR. The following letter relating to the "Reserves and Revenue as of December 31, 2000 From Certain Properties Owned by Mesa Royalty Trust" (the "Hugoton Reserve Report") summarizes such reserve study. References to the reserves of the Trust and the future net revenue and present worth attributable to the Trust interest in the Hugoton Reserve Report refer to the Trust's interest in the Hugoton Royalty

Properties. The Hugoton Reserve Report reflects estimated reserve quantities and future net revenue in a manner which is based upon a month of production without regard to time of receipt by the Trust and which differs from the manner in which the Trust recognizes and accounts for its royalty income.

A study of the proved oil and gas reserves attributable to the New Mexico portion of the San Juan Basin Royalty as of December 31, 2000 has been made by Conoco, the working interest owner of such properties. The Conoco Reserve Report (together with the PNR Reserve Report, the "Reserve Reports") beginning on page 11 regarding such properties reflects estimated reserve quantities.

Proved oil and gas reserves attributable to the Colorado portion of the San Juan Basin Royalty have been omitted from the Trust's reserve disclosures included in this Form 10-K, as they represent less than 5% of the Trust's total reserves and future net revenues.

For further information regarding the Net Overriding Royalty Interest, the Basis of Accounting for the Trust, and Reserves, see Notes 2, 3 and 6, respectively, in the Notes to Financial Statements under Item 8 of this Form 10-K.

[LOGO]

Tuesday, February 20, 2001

MESA Royalty Trust
Chase Bank of Texas, N.A. (as Trustee)
Chase Tower, Suite 1150
600 Travis Street
Houston TX 77002

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2000 of the extent and value of the proved natural gas liquids, natural gas and helium reserves of certain properties owned by the Mesa Royalty Trust, hereinafter referred to as the "Trust." The interest appraised consists of a 10.29282% (percent) net profits overriding royalty interest in certain properties administered by Pioneer Natural Resources USA, Inc., hereinafter referred to as "Pioneer." These properties are located in the Kansas Hugoton and Panoma-Council Grove fields in Kansas. Pioneer is 100 percent owned by Pioneer Natural Resources Company, the successor to Mesa Limited Partnership.

The reserve estimates are based on a detailed study of the Trust's properties. The method or combination of methods used in the study of each reservoir was tempered by experience in the area, consideration of the state of development of the reservoir, and the quality and completeness of basic data.

Reserves in this report are expressed as gross reserves and net reserves. Gross reserves are defined as the total estimated petroleum hydrocarbons remaining to be produced from the properties subsequent to December 31, 2000. Net reserves are defined as that portion of the gross reserves attributable to the Trust interest after deducting royalties and other interests owned by others.

Values shown herein are expressed in terms of future net revenue, future net cashflow and present worth. Future net revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves. Future net cashflow is calculated by deducting estimated production taxes, ad valorem taxes, lease operating expenses, and capital costs from the future net revenue. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. In this report, present worth values are reported using a discount rate of 10% (percent).

Reserve and revenue values shown in this report were estimated from projections of reserves and revenue attributable to the combined Pioneer and Trust interests (Combined Interest) in these properties. To calculate the net profits, the future net revenue for the aggregate of the Combined Interest in the subject properties was reduced by an overhead charge and by the deficit balance as described below if any. In addition, because the net profits interest does not participate in plant and gathering expenses, a portion of the net revenue attributable to the plant interests was excluded from this calculation; the excluded portion is 35 percent of the plant revenue less 100 percent of the plant and gathering expenses. When the adjusted net revenue resulting from this calculation was greater than zero, it was multiplied by the factor of 10.29282% (percent) to arrive at the future net revenue of the Trust. If the adjusted revenue for the period was negative, the trust revenue was set to zero and interest was charged on the deficit balance. The beginning deficit balance as of December 31, 2000, was zero and no deficit is estimated for the life of the properties.

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While estimates of reserves attributable to the Trust are shown in order to comply with requirements of the SEC, this is no precise method of allocating estimates of physical quantities of reserves between the working interest owners and the Trust. The net profits overriding royalty interest is not a working interest and the Trust does not own and is not entitled to receive any specific volume of reserves from the Trust. Reserve quantities in the previously mentioned reserve studies have been allocated based on the method referenced in the Reserve Reports. The quantities of reserves attributable to the Trust will be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Trust Properties. Therefore, the estimates of reserves set forth in the Reserve Reports are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest.

Estimates of reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information becomes available. Not only are such reserve and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

The development status shown herein represents the status applicable on December 31, 2000. In our preparation of the study, data available from wells drilled on the appraised properties through December 31, 2000 were used in estimating gross ultimate recovery. Gross production estimated to December 31, 2000 was deducted from gross ultimate recovery to arrive at the estimates of gross reserves as of December 31, 2000. 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 2000.

Petroleum reserves included in this report are classified as proved and are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analysis, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs as of the date the estimate is made. This included consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved - Reserves that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data. Commercial productivity has been established by actual production, successful testing, or in certain cases by favorable core analyses and electrical-log interpretation when the producing characteristics of the formation are known from nearby fields. Volumetrically, the structure, areal extent, volume, and characteristics of the reservoir are well defined by a reasonable interpretation of adequate subsurface well control and by known continuity of hydrocarbon-saturated material above known fluid contacts, if any, or above the lowest known structural occurrence of hydrocarbons.

Developed - Reserves that are recoverable from existing wells with current operating methods and expenses. Developed reserves include both producing and non-producing reserves. Estimates of producing reserves assume recovery by existing wells producing from present completion intervals with normal operating methods and expenses. Developed non-producing reserves are in reservoirs behind the casing or at minor depths below the producing zone and are considered proved

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by production from other wells in the field, by successful drill-stem tests, or by core analysis from the particular zones. Non-producing reserves require only moderate expense to be brought into production.

Undeveloped - Reserves that are recoverable from additional wells yet to be drilled. Undeveloped reserves are those considered proved for production by reasonable geological interpretation of adequate subsurface control in reservoirs that are producing or proved by other wells but are not recoverable from existing wells. This classification of reserves requires drilling of additional wells, major deepening of existing wells, or installation of enhanced recovery or other facilities.

Helium reserves were classified using the same standards as those described in the foregoing definitions of petroleum reserves. Since it is mixed in and produced with the natural gas reserves, the term gas as used herein applies to both gases, where appropriate, and the term natural gas is used to refer to hydrocarbon gas.

Estimates of the net proved reserves attributable to the Trust, as of December 31, 2000, are as follows:

TOTAL PROVED RESERVES:	
Natural Gas (Mcf)......................................	19,156,486
Helium (Mcf)...	64,145
Natural Gas Liquids (bbl)..............................	999,910
PROVED DEVELOPED RESERVES	
Natural Gas (Mcf)......................................	19,156,486

Helium (Mcf)...	64,145
Natural Gas Liquids (bbl)..............................	999,910

Proved natural gas liquid reserves and helium reserves are included herein for the Satanta plant, which was completed and placed on stream in the Hugoton field in Kansas during late 1993.

Future oil and gas producing rates estimated for this report are based on production rates considering the most recent figures available or, in certain cases, are based on estimates. The rates used for future production are within the capacity of the well or reservoir to produce.

Pioneer is continuing to upgrade the well gathering system, which improves deliverability of the wells. This increase in deliverability and the associated costs have been incorporated in the estimates included herein.

Gas volumes shown herein are expressed at standard conditions of 60 degrees Fahrenheit and at 14.65 pounds per square inch absolute. Gross volumes are reported as wet gas and the net volumes are reported as processed hydrocarbon sales; however, neither the gross or net volumes were reduced for plant fuel usage. The value of this fuel is deducted as part of the plant operating costs.

Revenue values in this report were estimated using current prices and costs. Future prices were estimated using guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board.

The assumptions used for estimating future prices and costs are as follows:

- Natural Gas Prices - Gas prices were held constant for the life of the properties.

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- Natural Gas Liquids and Helium Prices - Natural gas liquids and helium prices were held constant for the life of the properties.

- Operating and Capital Costs - Estimates of operating costs based on current costs were used for the life of the properties with no increase in the future based on inflation. Future capital expenditures were estimated using 2000 values and were not adjusted for inflation.

The estimated future net revenue, future net cashflow and present worth discounted at 10% (percent) attributable to the Trust Interest for the life of the Trust is as follows.

TRUST INTEREST:

Future Net Revenue ($)(1)................................	247,436,234
Future Lease Operating Expenses ($).......................	5,269,367
Future Net Production Taxes ($)...........................	6,211,400
Future Net Ad Valorem Taxes ($)...........................	14,783,255
Future Net Overhead Expense ($)...........................	11,837,182
Future Capital Expenditures ($)...........................	751,702
Future Net Cashflow ($)...................................	208,583,328
Present Worth at 10 Percent ($)(1)........................	84,416,102

1. Future income tax expenses were not taken into account in the preparation of these estimates. Approximately 2 percent of the present worth is estimated to come from helium sales.

In our opinion, the information relating to the estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 10-13, 15 and 30(a)-(b) of Statement of Financial Accounting Standards No. 69 (November 1982) of the Financial Accounting Standards Board and Rules 4-10(a)(1)-(13) of Regulation S-X and Rule 302(b) of Regulation S-K of the Securities and Exchange Commission; provided, however, (I) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (II) minor amounts of revenue from helium produced with the natural gas are included herein.

To the extent the above enumerated rules, regulations, and statements require determinations of an accounting or legal nature or information beyond the scope of this report, we are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefore.

Submitted,

/s/ JOHN PETERS

John Peters

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CONOCO INC.
LETTER REPORT
DATED
MARCH 8, 2001
ON
RESERVES AND REVENUE
AS OF
DECEMBER 31, 2000
FROM
CERTAIN PROPERTIES
OWNED BY
MESA ROYALTY TRUST

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RANDALL L. DARR
Leader - Reservoir Management
Reservoir Technology Center
Exploration Production Technology

P.O. Box 2197
Houston, Texas 77252
(281) 293-1404

March 8, 2001

Mesa Royalty Trust
Chase Bank of Texas, N.A.
Suite 1150
600 Travis Street

Houston, Texas 77002

Re: MESA ROYALTY TRUST RESERVES AS OF DECEMBER 31, 2000
SAN JUAN BASIN PROPERTIES, NEW MEXICO

Gentlemen:

Pursuant to your request, estimates have been prepared as of December 31, 2000 of the extent and value of proved natural gas, condensate, and natural gas liquid reserves of certain properties owned by the Mesa Royalty Trust, hereinafter referred to as "MRT". The MRT interest appraised consists of a 10.29282 percent net royalty interest in certain San Juan Basin properties administered by Conoco.

Reserves in this report are expressed as Conoco net reserves and MRT net reserves. Conoco net reserves are defined as Conoco's net share of estimated petroleum hydrocarbons remaining to be produced from the properties after December 31, 2000. MRT net reserves are defined as that portion of the Conoco net reserves attributable to the interest owned by MRT.

Values shown herein are expressed in terms of future revenue, future cash flow, and present worth. Future revenue is that revenue which will accrue from production and sale of the estimated net reserves. Future cash flow is calculated by deducting estimated production and ad valorem taxes, operating and transportation expenses, capital costs, and abandonment costs from the future revenue. Federal income taxes are not taken into account in the preparation of these estimates. Present worth is defined as future cash flow discounted at a specified discount rate compounded monthly over the expected period of realization. A discount rate of 10 percent is used in this report.

Reserves attributable to the MRT interest are calculated by allocating to MRT a portion of the Conoco net reserves based on future cash flow. Because reserves volumes are estimated using future cash flow, a change in prices or costs will result in changes of reserves. Therefore, the MRT net reserves will vary if different price and cost assumptions are used.

Petroleum reserves included in this report are classified as proved and judged to be economically producible in future years from known reservoirs under existing economic and operating conditions. Total proved reserves are the sum of developed and undeveloped reserves. Proved developed reserves are those recoverable from existing wells with current operating methods and expenses, and thus require little or no capital expenditure to produce. Proved undeveloped reserves are those which require major capital expenditures for new wells and/or facilities. Estimates of the MRT net reserves

and production as of December 31, 2000 are tabulated below along with the MRT net reserves reported last year for comparison.

MRT NET PROVED RESERVES SAN JUAN BASIN DEVELOPED--UNDEVELOPED	CONVENTIONAL RESERVOIRS		FRUITLAND COAL RESERVOIRS		TOTAL ALL RESERVO	
	12/31/99	12/31/00	12/31/99	12/31/00	12/31/99	12

Natural Gas, MMscf..................	15,243	19,697	957	1,941	16,200	2
Condensate, Mbbl.....................	70	90	0	0	70	
Natural Gas Liquids, Mbbl............	1,000	1,266	0	0	1,000	

MRT NET PROVED RESERVES SAN JUAN BASIN DEVELOPED ONLY	CONVENTIONAL RESERVOIRS		FRUITLAND COAL RESERVOIRS		TOTAL ALL RESERVO	
	12/31/99	12/31/00	12/31/99	12/31/00	12/31/99	12
Natural Gas, MMscf..................	14,463	18,689	957	1,941	15,420	2
Condensate, Mbbl.....................	65	85	0	0	65	
Natural Gas Liquids, Mbbl............	949	1,201	0	0	949	

Total MRT reserves increased in 2000 due to improvements in price. Proved Developed Behind Pipe and Proved Undeveloped reserves increased in 2000 due to an increased development plan. Many of the Proved Undeveloped Reserves will be accessed in 2001 through an active development and re-completion program. The reserves value reflect natural gas shrinkage of 12.791 percent for conventional gas reservoirs due to processing and plant fuel use, and an average net back to producing properties of 61 percent of recovered natural gas liquids. The Fruitland Coal reservoir has dry gas (no natural gas liquids) and therefore is not subject to shrinkage due to liquids extraction.

Product prices and operating costs used for yearend 2000 are shown in the table below, along with those used last year for comparison. Prices and operating costs are held constant over the life of the properties. The December 2000 product prices are substantially higher than the December 1999 prices.

PRODUCT PRICES	DECEMBER 1999	DECEMBER 2000
Conventional Nat. Gas. $/Mscf.............................	2.33	9.23
Coal Natural Gas, $/Mscf..................................	1.98	7.90
Condensate, $/Bbl...	21.54	28.62
Natural Gas Liquids, $/Bbl................................	12.01	16.39

Revenue and cash flow values in this report are based on product prices for San Juan Basin effective on December 31, 2000. The gas price excludes a transportation expense of $0.45 per Mcf for conventional gas and $0.94 per Mcf for Fruitland Coal gas. The price also excludes combined production and ad valorem tax rates of 10.6 percent and 9.2 percent of revenue for conventional and Fruitland Coal gas, respectively. These taxes compare with the 1999 rates of 10.9 percent for conventional gas and 9.5 percent for Fruitland Coal. The taxes and transportation expenses are also excluded from the annual per well operating costs tabulated below. Fruitland Coal operating costs on a per well basis were higher in 2000 than in 1999 due to an extensive effort to maximise production volumes within the tax credit window. An increase in the total number of Net Active Conventional Completions is due to an active development program.

OPERATING COSTS	NET ACTIVE COMPLETIONS		OPERATING COSTS ($/WELL/YEAR)	
	12/31/99	12/31/00	12/31/99	12/31/00
Conventional Gas..............................	417	430	17,000	18,900
Fruitland Coal Gas...........................	35	35	48,800	56,200

A summary of estimated future revenue, taxes, costs, cash flow, and present worth attributable to CONOCO'S net reserves as of December 31, 2000 is shown in the table below. The 1999 numbers are included for comparison. All costs are yearend 2000 estimates and are not adjusted for inflation. Cash flow and present worth are reported on a before federal income tax (BFIT) basis.

CONOCO NET INTEREST SAN JUAN BASIN	CONVENTIONAL RESERVOIRS		FRUITLAND COAL RESERVOIRS		TOTAL ALL RESER	
	12/31/99	12/31/00	12/31/99	12/31/00	12/31/99	12/3
Future Revenue, M$.................	765,131	2,574,288	58,871	209,579	824,002	2,78
Production & Ad Valorem Taxes, M$............................	83,399	273,644	5,605	19,218	89,004	29
Operating & Transportation Costs, M$............................	185,874	284,455	33,670	40,843	219,544	32
Abandonment Costs, M$.............	1,742	2,506	127	171	1,869	
Capital Costs, M$.................	17,836	20,776	1,055	405	18,891	2
Future BFIT Cash Flow, M$..........	476,280	1,992,885	18,414	148,942	494,694	2,14
Deficit Balance, M$...............	0	0	0	0	0	
Future BFIT Cash Flow Subject to MRT Interest, M$................	476,280	1,992,885	18,414	148,942	494,694	2,14
Present Worth @ 10%, M$...........	187,405	791,063	14,640	106,012	202,045	89

Conoco's future revenues are significantly higher due to the increased product prices.

Operating costs are higher for both the conventional gas and Fruitland Coal due to increased transportation and operating costs and the additional operating expense associated with recovery of the new incremental reserves.

Capital costs are associated with projects required to produce undeveloped proved reserves and maintain existing production of developed reserves. The increase in capital for the conventional reservoirs reflects the additional wells needed to develop the increased proved undeveloped reserves.

A summary of estimated future cash flow and present worth attributable to the MRT interest as of December 31, 2000 is tabulated below along with what was reported last year for comparison.

	CONVENTIONAL RESERVOIRS		FRUITLAND COAL RESERVOIRS		TOTAL ALL RESERV	
MRT INTEREST (10.29282%) SAN JUAN BASIN	12/31/99	12/31/00	12/31/99	12/31/00	12/31/99	1
Future BFIT Cash Flow, M$............	49,023	205,124	1,895	15,330	50,918	2
Present Worth @ 10%, M$..............	19,289	81,423	1,507	10,912	20,796	

Compared to last year, future cash flow and present worth is higher for conventional gas and Fruitland Coal, reflecting the increase in product prices.

The information relating to estimated proved reserves (natural gas, condensate, natural gas liquids), estimated future revenue from proved reserves, and present worth of cash flow contained in this report has been prepared in accordance with regulations of the Financial Accounting Standards Board and Securities and Exchange Commission.

Sincerely,

Randall Darr

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. The preceding reserve data in the Reserve Reports represent estimates only and should not be construed as being exact. 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 Conoco. Accordingly, reserve estimates are often different from the quantities of hydrocarbons that are ultimately recovered.

While estimates of reserves 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 reserves 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. Reserve quantities in the previously mentioned reserve studies have been allocated based on the method referenced in the Reserve Reports. The quantities of reserves attributable to the Trust will be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Royalty Properties. Therefore, the estimates of reserves set forth in the Reserve Reports are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest.

Moreover, the discounted present values in 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. In accordance with applicable regulations of the SEC, estimated future net revenues were based on current prices and costs, whereas actual future prices and costs may be materially greater or less. The estimates in the Reserve Reports use market prices as of the end of the year. These prices (having a weighted average of $9.85 per Mcf for Hugoton properties and $9.11 per Mcf for San Juan Basin properties as of December 31, 2000) were held constant over the estimated life of the Royalty Properties. Such prices were influenced by seasonal demand for natural gas and may not be the most appropriate or representative prices to use for estimating future revenues or related reserve data. The average price of natural gas from the Royalty Properties during 2000 was $2.97 per Mcf, representing a combination of contract prices and spot market prices.

The future net revenues shown by the Reserve Reports have not been reduced for costs and expenses of the Trust, which are expected to approximate $50,000 annually. The costs and expenses of the Trust may increase in future years, depending on the amount of Royalty income, increases in accounting, engineering, legal and other professional fees and other factors.

Standardized measure at December 31, 2000 was calculated using natural gas prices of $9.85 per Mcf for Hugoton properties and $9.11 per Mcf for San Juan properties. Natural gas prices have declined significantly to approximately $5.00 per Mcf in March 2001; consequently, the discounted future net cash flows would be significantly reduced if the standardized measure was calculated using March 2001 prices.

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.

CONTRACTS

HUGOTON FIELD

Natural gas and natural gas liquids produced by PNR from the Hugoton field and attributable to the Royalty accounted for approximately 63% of the Royalty income of the Trust during 2000.

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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 including Williams Energy Supply ("WESCO"), Oneok Gas Marketing, Inc., Amoco Production Company and Anadarko Energy Services, 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 the Hugoton Royalty Properties were higher in 2000 compared to 1999.

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 being effective June 1, 2000. PNR has extended the contract to June 1, 2001. 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 was assigned to Midcontinent Market Center.

Allowable rates of production in the Hugoton field are set by the KCC based on the level of market demand. The Hugoton field allowable for the period October 1, 2000 through March 31, 2001, was 160.7 billion cubic feet of gas, compared with 179.6 billion cubic feet of gas during the same period last year.

SAN JUAN BASIN

Natural gas produced from the San Juan Basin field and attributable to the Royalty accounted for approximately 37% of the Royalty income of the Trust during 2000. 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 has been 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. In late 1999 and 2000, demand for natural gas increased as a result of the increase in clean burning natural gas fired power generation, the increase in the usage of electrical power fueled by the expanding U.S. economy and a return to seasonally cold winters. The annual average wellhead price for natural gas peaked in 1984 at $2.66 per Mcf and declined to $1.55 in 1995. Annual wellhead prices generally increased to $2.32 per Mcf in 1997, decreased to $1.94 per Mcf in 1998, increased to $2.08 per Mcf in 1999 then increased again to $3.35 per Mcf in 2000, 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 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 concerns, 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 recent years, the FERC has required interstate pipeline companies to "unbundle" their services. To the extent a pipeline company or its sales affiliate makes gas sales as a merchant in the future, it does so pursuant to private contracts in direct competition with all other sellers, such as the working interest owners. In recent years, the FERC also has pursued a number of other policy initiatives which could significantly affect the marketing of natural gas. Several of these initiatives are intended to enhance competition in natural gas markets, although some, such as "spindowns" of gathering assets, may have the adverse effect of increasing the cost of doing business on some in the industry. Generally, the FERC retained its existing tests for determining the jurisdictional status of offshore facilities, but eased the application of its jurisdiction over facilities in water depths of 200 meters or more. On February 9, 2000, the FERC issued Order No. 637, which permits, and in some cases requires, interstate natural gas pipelines to make certain changes to the nature of interstate transportation services. In Order No. 637-A, the FERC made certain clarifying adjustments to the regulations promulgated in Order No. 637. In Order No. 637-B, the FERC denied all further requests for rehearing. Order Nos. 637, ET SEQ. currently are pending judicial review. In addition to the changes implemented through Order No. 637, the FERC has stated that it will institute a review of its regulatory model in light of the changes in the natural gas industry. As to all of these recent FERC initiatives, the working interest owners have advised the Trust that the on-going, or, in some instances, preliminary evolving nature of these regulatory initiatives makes it impossible at this time 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 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.

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.

ITEM 2. PROPERTIES.

Reference is made to Item 1 of this Form 10-K.

ITEM 3. LEGAL PROCEEDINGS.

There are no pending legal proceedings to which the Trust is a party.

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 2000.

PART II

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

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, 2000, were as follows:

	2000				
QUARTER	HIGH	LOW	DISTRIBUTION	HIGH	
First	$47.75	$42.25	$0.8794	$44.88	$

Second	$42.75	$40.00	$0.7682	$46.50	$
Third..	$40.38	$37.88	$1.2270	$49.00	$
Fourth.......................................	$42.50	$40.00	$1.4345	$48.25	$

At March 23, 2000, the 1,863,590 units outstanding were held by 1,339 unitholders of record.

ITEM 6. SELECTED FINANCIAL DATA.

	2000	1999	1998	1997	1996
Royalty income................	$ 7,960,109	$ 5,475,497	$ 6,209,778	$ 9,287,406	$ 7,669,0
Distributable income..........	$ 8,030,448	$ 5,504,362	$ 6,248,216	$ 9,358,576	$ 7,689,3
Distributable income per unit........................	$ 4.3091	$ 2.9536	$ 3.3528	$ 5.0218	$ 4.12
Total assets at year end......	$14,545,212	$14,358,414	$14,902,521	$17,616,866	$18,975,9

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

LIQUIDITY AND CAPITAL RESOURCES

As discussed under "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 Note 6 in 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.

FINANCIAL REVIEW

YEARS 2000 AND 1999

The Trust's Royalty income was $7,960,109 in 2000, an increase of approximately 45%, as compared to $5,475,497 in 1999, primarily as a result of higher natural gas and natural gas liquids prices.

Royalty income from the Hugoton Royalty Properties was $5,051,072 in 2000, an increase of approximately 49%, as compared to $3,400,082 in 1999, primarily as a result of higher natural gas and natural gas liquids prices in 2000.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $3.03 per Mcf and $19.24 per barrel, respectively, in 2000 as compared to $1.97 per Mcf and $10.24 per barrel, respectively, in 1999. Net production attributable to the Hugoton Royalty was 1,142,851 Mcf of natural gas and 82,549 barrels of natural gas liquids in 2000 as compared with 1,250,300 Mcf of natural gas and 91,503 barrels of natural gas liquids in 1999.

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 $2,909,037 in

2000 as compared to $2,075,415 in 1999. The increase in Royalty income was due primarily to increased natural gas and natural gas liquids prices in 2000. No Royalty income was received from the San Juan Basin Royalty Properties located in the state of Colorado in 2000 or 1999, as costs associated with the Fruitland Coal drilling program on Royalty Properties in that state have not been fully recovered. The San Juan Basin development drilling program has no effect on Royalty income or distributions relating to the Hugoton Royalty.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty Properties was $2.88 per Mcf and $21.51 per barrel, respectively, in 2000 compared with $1.81 per Mcf and $12.54 per barrel, respectively, in 1999. Net production attributable to the San Juan Basin Royalty was 677,569 Mcf of natural gas and 44,521 barrels of natural gas liquids, oil and condensate in 2000 as compared to 865,312 Mcf of natural gas and 40,606 barrels of natural gas liquids, oil and condensate in 1999.

As more fully discussed in Note 6 of the Notes to Financial Statements contained in Item 8 of this Form 10-K, production attributable to the Trust's interest in the Royalty Properties is calculated based on Royalty income received from the applicable net profits interest owned by the Trust.

Conoco has informed the Trust that it believes the production from the Fruitland Coal formation will generally qualify for the tax credits provided under Section 29 of the Code. See "Description of the Units--Federal Income Tax Matters--Section 29 Credit" under Item 1 of this Form 10-K.

YEARS 1999 AND 1998

The Trust's Royalty income was $5,475,497 in 1999, a decrease of approximately 12%, as compared to $6,209,778 in 1998, primarily as a result of lower natural gas production and natural gas prices.

Royalty income from the Hugoton Royalty Properties was $3,400,082 in 1999, a decrease of approximately 20%, as compared to $4,235,415 in 1998, as a result of both decreased natural gas and natural gas liquids prices and production.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $1.97 per Mcf and $10.24 per barrel, respectively, in 1999 as compared to $2.10 per Mcf and $10.64 per barrel, respectively, in 1998. Net production attributable to the Hugoton Royalty was 1,250,300 Mcf of natural gas and 91,503 barrels of natural gas liquids in 1999 as compared with 1,539,202 Mcf of natural gas and 94,275 barrels of natural gas liquids in 1998.

Royalty income from the San Juan Basin Royalty Properties located in the state of New Mexico was $2,075,415 in 1999 as compared to $1,974,363 in 1998 due primarily to an increase in natural gas and natural gas liquids production as well as an increase in natural gas liquid prices. No Royalty income was received from Amoco with respect to the San Juan Basin Royalty Properties located in the state of Colorado in 1999 or 1998 as costs associated with the development drilling program from Royalty Properties in that state have not been fully recovered.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty Properties was $ 1.81 per Mcf and $12.54 per barrel, respectively, in 1999 compared with $1.92 per Mcf and $11.12 per barrel, respectively, in 1998. Net production attributable to the San Juan Basin Royalty was 865,312 Mcf of natural gas and 40,606 barrels of natural gas liquids, oil and condensate in 1999 as compared to 811,007 Mcf of natural gas and 37,521 barrels of natural gas liquids, oil and condensate in 1998.

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

	HUGOTON		SAN JUAN BASIN	
	NATURAL GAS	NATURAL GAS LIQUIDS(2)	NATURAL GAS	OIL, CONDENSATE AND NATURAL GAS LIQUIDS(2)
Year ended December 31, 2000:				
The Trust's proportionate share of--				
Gross proceeds	$4,430,755	$1,588,234	$4,412,109	$1,181,184
Less the Trust's proportionate share of--				
Capital costs recovered(1)	(127,513)	--	(826,428)	--
Operating costs	(840,404)		(1,600,283)	(223,545)
Interest on cost carryforward	--	--	(34,000)	--
Royalty income	$3,462,838	$1,588,234	$1,951,398	$ 957,639
Average sales price	$ 3.03	$ 19.24	$ 2.88	$ 21.51
Net production volumes attributable	(Mcf)	(Bbls)	(Mcf)	(Bbls)
to the Royalty paid	1,142,851	82,549	677,569	44,521
Year ended December 31, 1999:				
The Trust's proportionate share of--				
Gross proceeds	$3,382,152	$ 936,991	$3,119,929	$ 683,584
Less the Trust's proportionate share of--				
Capital costs recovered(1)	(32,956)	--	(83,475)	--
Operating costs	(886,105)	--	(1,434,069)	(174,383)
Interest on cost carryforward	--	--	(36,171)	--
Royalty income	$2,463,091	$ 936,991	$1,566,214	$ 509,201
Average sales price	$ 1.97	$ 10.24	$ 1.81	$ 12.54
Net production volumes attributable	(Mcf)	(Bbls)	(Mcf)	(Bbls)
to the Royalty paid	1,250,300	91,503	865,312	40,606
Year ended December 31, 1998:				
The Trust's proportionate share of--				
Gross proceeds	$4,315,417	$1,003,090	$3,838,538	$ 594,315
Less the Trust's proportionate share of--				
Capital costs recovered(1)	(76,949)	--	(546,352)	--
Operating costs	(1,006,143)		(1,699,546)	(177,086)
Interest on cost carryforward	--	--	(35,506)	--
Royalty income	$3,232,325	$1,003,090	$1,557,134	$ 417,229
Average sales price	$ 2.10	$ 10.64	$ 1.92	$ 11.12
Net production volumes attributable	(Mcf)	(Bbls)	(Mcf)	(Bbls)
to the Royalty paid	1,539,202	94,275	811,007	37,521

For a discussion of the method used to compute the net production volumes in the table above, see Note 6 in the Notes to Financial Statements.

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(1) Capital costs recovered represents capital costs incurred during the current or prior periods to the extent that such costs have been recovered by the applicable working interest owners from current period gross proceeds. Cost carryforward represents capital costs incurred during the current or prior periods which will be recovered from future period gross proceeds. The cost carryforward resulting from the Fruitland Coal drilling program was $390,457, $452,188 and $456,377 at December 31, 2000, 1999 and 1998, respectively, and relate solely to the San Juan Basin Colorado properties. See "Description of Royalty Properties--San Juan Basin Fruitland Coal Drilling" for additional information regarding the Fruitland Coal drilling program.

(2) Gross proceeds attributable to natural gas liquids for the Hugoton and San Juan Basin properties are net of a volumetric in-kind processing fee retained by PNR and Conoco, respectively.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

MESA ROYALTY TRUST
STATEMENTS OF DISTRIBUTABLE INCOME

	YEARS ENDED DECEMBER 31,		
	2000	1999	1998
Royalty income	$7,960,109	$5,475,497	$6,209,778
Interest income	97,383	54,911	73,714
General and administrative expenses	(27,044)	(26,046)	(35,276)
Distributable income	$8,030,448	$5,504,362	$6,248,216
Distributable income per unit	$ 4.3091	$ 2.9536	$ 3.3528

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	DECEMBER 31,	
	2000	1999
ASSETS		
Cash and short-term investments	$ 2,658,110	$ 1,678,624
Interest receivable	25,199	6,528
Net overriding royalty interests in oil and gas properties	42,498,034	42,498,034
Less: accumulated amortization	(30,636,131)	(29,824,772)

Total assets	$ 14,545,212	$ 14,358,414
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 2,683,309	$ 1,685,152
Trust corpus (1,863,590 units of beneficial interest authorized and outstanding)	11,861,903	12,673,262
Total liabilities and trust corpus	$ 14,545,212	$ 14,358,414

STATEMENTS OF CHANGES IN TRUST CORPUS

	YEARS ENDED DECEMBER 31,		
	2000	1999	1998
Trust corpus, beginning of year	$12,673,262	$13,889,555	$15,512,726
Distributable income	8,030,448	5,504,362	6,248,216
Distributions to unitholders	(8,030,448)	(5,504,362)	(6,248,216)
Amortization of net overriding royalty interests	(811,359)	(1,216,293)	(1,623,171)
Trust corpus, end of year	$11,861,903	$12,673,262	$13,889,555

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 a 90% net overriding royalty interest (the "Royalty") 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"). On April 30, 1991, MLP sold its interests in the Royalty Properties located in San Juan Basin field to Conoco Inc. ("Conoco"). Conoco 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 Amoco Production Company ("Amoco"), a subsidiary of BP Amoco. 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 Conoco. The San Juan Basin Royalty Properties located in Colorado are operated by Amoco. As used in this report, PNR refers to the operator of the Hugoton Royalty Properties, Conoco refers to the operator of the San Juan Basin Royalty Properties, other than the portion of such properties located in Colorado, and Amoco refers to the operator of the Colorado San Juan Basin Royalty Properties unless otherwise indicated.

The Chase Manhattan Bank (the "Trustee") successor by merger to Chase Bank of Texas, National Association is trustee for the Trust. 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

(f) PNR, Conoco and Amoco (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 instruments conveying the Royalty, the Working Interest Owners will calculate and pay the Trust each month an amount equal to 90% of the net proceeds for the preceding month. The Trust Indenture was amended in 1985, the effect of which was an overall reduction of approximately 88.56% in the size of the Trust; therefore, the Trust is now entitled to receive 90% of 11.44% of the net proceeds for the preceding month. Generally, net proceeds means the excess of the amounts received by the Working Interest Owners from sales of oil and gas from the Royalty Properties over the operating and capital costs incurred.

The initial carrying value of the Royalty represented the net book value assigned by PNR to the Royalty Properties at the date of transfer to the Trust. 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 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.

(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) SUPPLEMENTAL RESERVE INFORMATION (UNAUDITED)

Estimates of the proved oil and gas reserves attributable to the Hugoton Royalty Properties as of December 31, 2000, 1999 and 1998 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 net profits interest 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 on royalty income. Because the net reserve volumes attributable to the Trust net profits 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 net profits interest will vary if different future price and cost assumptions are used. Only costs necessary to 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 portion of the San Juan Basin Royalty Properties are based on a reserve report prepared by Conoco. These estimates were prepared in accordance with SEC regulations and on a basis generally consistent with those used to derive the oil and gas reserves attributable to the Hugoton Royalty Properties.

Estimates of proved oil and gas reserves attributable to the Colorado portion of the San Juan Basin Royalty Properties have been omitted from the Trust's reserve disclosures, as they represent less than 5% of the Trust's total reserves and future net revenues.

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

(6) SUPPLEMENTAL RESERVE INFORMATION (UNAUDITED) (CONTINUED)

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. Certain reclassifications have been made to prior year amounts to conform to the current year presentation.

ESTIMATED QUANTITIES OF PROVED AND PROVED DEVELOPED RESERVES

(UNAUDITED)

	OIL, CONDENSATE AND NATURAL GAS LIQUIDS	NATURAL GAS
	(BBLS)	(MCF)
Proved Reserves:		
December 31, 1997	1,686,509	35,605,125
Revisions to previous estimates	65,215	(1,841,219)
Production	(131,796)	(2,350,209)
December 31, 1998	1,619,928	31,413,697
Revisions to previous estimates	484,393	3,314,482
Production	(132,109)	(2,115,612)
December 31, 1999	1,972,212	32,612,567
Revisions to previous estimates	510,768	10,066,484
Production	(127,070)	(1,820,420)
December 31, 2000	2,355,910	40,858,631
Proved Developed Reserves:		
December 31, 1998	1,591,928	31,019,697
December 31, 1999	1,916,212	31,833,567
December 31, 2000	2,285,910	39,850,631

- The estimated quantities of proved reserves for oil, condensate and natural gas liquids include oil and condensate reserves at December 31 of the respective years as follows: 2000, 90,000 Bbls; 1999, 70,000 Bbls, and 1998, 57,000 Bbls.

- The Hugoton Royalty represents 42%, 46% and 46% of the estimated proved oil, condensate and natural gas liquids reserves and 47%, 50% and 54% of the estimated proved natural gas reserves as of December 31 of 2000, 1999 and 1998, respectively.

(6) SUPPLEMENTAL RESERVE INFORMATION (UNAUDITED) (CONTINUED)

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

	DECEMBER 31,	
	2000	1999

	(IN THOUSANDS)	
The Trust's proportionate share of future gross proceeds....	$ 533,972	$163,887
Less the Trust's proportionate share of--		
Future operating costs..................................	(101,727)	(54,849)
Future capital costs....................................	(3,207)	(2,873)
Future royalty income.....................................	429,038	106,165
Discount at 10% per annum.................................	(252,287)	(59,470)
Standardized measure of future royalty income from proved oil and gas reserves..................................	$ 176,751	$ 46,695

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

	DECEMBER 31,		
	2000	1999	1998
	(IN THOUSANDS)		
Standardized measure at beginning of year..................	$ 46,695	$30,204	$ 47,029
Revisions of previous estimates..........................	27,654	5,189	(3,790)
Net changes in price and production costs................	105,692	13,757	(11,528)
Royalty income...	(7,960)	(5,475)	(6,210)
Accretion of discount....................................	4,670	3,020	4,703
Net changes in standardized measure......................	130,056	16,491	(16,825)
Standardized measure at end of year........................	$176,751	$46,695	$ 30,204

- The Hugoton Royalty represents approximately 48% and 55% of the standardized measure of future royalty income for 2000 and 1999, respectively.

- Standardized measure at December 31, 2000 was calculated using natural gas prices of $9.85 per Mcf for Hugoton properties and $9.11 per Mcf for San Juan properties. Natural gas prices have declined significantly to approximately $5.00 per Mcf in March 2001; consequently, the discounted future net cash flows would be significantly reduced if the standardized measure was calculated using March 2001 prices.

(7) SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

SUMMARIZED QUARTERLY RESULTS
THREE MONTHS ENDED

	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER
2000:				
Royalty income	$1,621,389	$1,423,595	$2,261,759	$2,653,3
Distributable income	$1,638,750	$1,431,676	$2,286,614	$2,673,4
Distributable income per unit	$ .8794	$ .7682	$ 1.2270	$ 1.43
1999:				
Royalty income	$1,208,881	$1,206,359	$1,376,799	$1,683,4
Distributable income	$1,211,895	$1,207,226	$1,400,089	$1,685,1
Distributable income per unit	$ .6503	$ .6478	$ .7513	$ .90

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REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

TO THE CHASE MANHATTAN BANK (TRUSTEE)
AND THE UNITHOLDERS OF THE MESA ROYALTY TRUST:

We have audited the accompanying statements of assets, liabilities and trust corpus of the Mesa Royalty Trust as of December 31, 2000 and 1999, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2000. 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 auditing standards generally accepted in the 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 accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the Mesa Royalty Trust as of December 31, 2000 and 1999, and its distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2000, on the basis of accounting described in Note 3.

ARTHUR ANDERSEN LLP

Houston, Texas
March 23, 2001

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

There are no directors or executive officers of the Registrant. The Trustee is a corporate trustee which may be removed by the affirmative vote of the majority at a meeting of the holders of units of beneficial interest of the Trust at which a quorum is present.

ITEM 11. EXECUTIVE COMPENSATION.

Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

(A) SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS.

The following information has been taken from filings with the Securities and Exchange Commission on Forms 13D and 13G and Form 4.

TITLE OF CLASS OF VOTING SECURITIES	NAME AND ADDRESS OF BENEFICIAL OWNER	AMOUNT AND NATURE OF BENEFICIAL OWNERSHIP(1)	PERCENT OF CLASS
Units of Beneficial Interest.......	Alpine Capital, L.P. 201 Main Street, Suite 3100 Fort Worth, Texas 76102	781,016(2)	41.9%
Units of Beneficial Interest.......	Beck, Mack & Oliver LLC 330 Madison Avenue New York, NY 10017	296,868(3)	15.9%

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(1) Under applicable regulations of the Securities and Exchange Commission, securities are deemed to be "beneficially" owned by a person who directly or indirectly holds or shares voting power or investment power with respect thereto.

(2) Information obtained from Schedule 13D Amendment No. 15 dated February 2, 2000 of Alpine Capital, L.P. ("Alpine"), Robert W. Bruce III, Algenpar, Inc., J. Taylor Crandall, The Anne T. Bass and Robert M. Bass Foundation, Anne T. Bass and Robert M. Bass, and from Form 4's filed by Alpine, Mr. Bruce, Algenpar, Inc. and Mr. Crandall dated February 9, 2000. Alpine directly owns and has sole voting and dispositive power with respect to all of such units. Such number of units does not include 51,284 units (which constitutes approximately 2.8% of the 1,863,590 units outstanding) directly owned by The Anne T. Bass and Robert M. Bass Foundation (the "Foundation"). Mr. Bruce, by virtue of his position as a general partner of Alpine and as a principal of The Robert Bruce Management Co. Inc., which has shared dispositive power with respect to the 51,284 units owned by the Foundation, may be deemed to be a beneficial owner of the 781,016 units owned by Alpine and the 51,284 units owned by the Foundation. Mr. Crandall, by virtue of his position as President and sole stockholder of Algenpar, Inc., which is one of two general partners of Alpine, and as a director of the Foundation, may also be deemed to be a beneficial owner of the 781,016 units owned by Alpine and the 51,284 units owned by the Foundation.

(3) Information obtained from Schedule 13G dated January 18, 2001 of Beck, Mack & Oliver LLC ("BMO"). BMO has shared dispositive power with respect to all of such units. All of such units are owned by the investment advisory clients of BMO.

(B) SECURITY OWNERSHIP OF MANAGEMENT.

Not applicable.

(C) CHANGES IN CONTROL. Registrant knows of no arrangements, including the pledge of securities of the Registrant, the operation of which may at a subsequent date result in a change in control of the Registrant.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Not applicable.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K.

(A)(1)FINANCIAL STATEMENTS

The following financial statements are set forth under Part II, Item 8 of this Annual Report on Form 10-K on the pages indicated.

(A)(2)SCHEDULES

Schedules have been omitted because they are not required, not applicable or the information required has been included elsewhere herein.

(A)(3)EXHIBITS

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference.)

		SEC FILE OR REGISTRATION NUMBER	EXHIBIT NUMBER
4(a)	*Mesa Royalty Trust Indenture between Mesa Petroleum Co. and Texas Commerce Bank National Association, as Trustee, dated November 1, 1979..	2-65217	1(a)

4(b)	*Overriding Royalty Conveyance between Mesa Petroleum Co. and Texas Commerce Bank, as Trustee, dated November 1, 1979...	2-65217	1(b)
4(c)	*First Amendment to the Mesa Royalty Trust Indenture dated as of March 14, 1985 (Exhibit 4(c) to Form 10-K for year ended December 31, 1984 of Mesa Royalty Trust).............	1-7884	4(c)
4(d)	*Form of Assignment of Overriding Royalty Interest, effective April 1, 1985, from Texas Commerce Bank National Association, as Trustee, to MTR Holding Co. (Exhibit 4(d) to Form 10-K for year ended December 31, 1984 of Mesa Royalty Trust)..	1-7884	4(d)
4(e)	*Purchase and Sale Agreement, dated March 25, 1991, by and among Mesa Limited Partnership, Mesa Operating Limited Partnership and Conoco, as amended on April 30, 1991 (Exhibit 4(e) to Form 10-K for year ended December 31, 1991 of Mesa Royalty Trust)....................................	1-7884	4(e)

(B) REPORTS ON FORM 8-K.

No reports on Form 8-K were filed with the Securities and Exchange Commission by the Trust during the fourth quarter of 2000.

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SIGNATURES

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

MESA ROYALTY TRUST

By THE CHASE MANHATTAN BANK, TRUSTEE

By /s/ PETE FOSTER

Pete Foster
SENIOR VICE PRESIDENT & TRUST OFFIC

March 23, 2000

The Registrant, Mesa Royalty Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided.

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