MESA ROYALTY TRUST/TX
Form 10-Q
November 09, 2006

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2006

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

FOR THE TRANSITION PERIOD FROM TO

Commission File Number: 1-07884

MESA ROYALTY TRUST

(Exact Name of Registrant as Specified in its Charter)

Texas (State or other Jurisdiction of Incorporation or Organization)	**76-6284806** (I.R.S. Employer Identification No.)
The Bank of New York Trust Company, N.A., Trustee **Global Corporate Trust** **221 West Sixth Street** **Austin, Texas** (Address of Principal Executive Offices)	**78701** (Zip Code)

1-800-852-1422

(Registrant s Telephone Number, Including Area Code)

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 o

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

Large accelerated filer o Accelerated filer x Non-accelerated filer o

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

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date. As of November 9, 2006 1,863,590 Units of Beneficial Interest in Mesa Royalty Trust.

PART I FINANCIAL INFORMATION

Item 1. ***Financial Statements.***

MESA ROYALTY TRUST
STATEMENTS OF DISTRIBUTABLE INCOME
(Unaudited)

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
Royalty income	$ 2,022,637	$ 2,396,815	$ 8,075,874	$ 7,180,617
Interest income	5,099	4,340	19,441	11,500
General and administrative expense	(18,131)	(14,021)	(56,564)	(53,633)
Distributable income	$ 2,009,605	$ 2,387,134	$ 8,038,751	$ 7,138,484
Distributable income per unit	$ 1.0784	$ 1.2809	$ 4.3136	$ 3.8305
Units outstanding	1,863,590	1,863,590	1,863,590	1,863,590

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	September 30, 2006 (Unaudited)	December 31, 2005
ASSETS		
Cash and short-term investments	$ 2,004,506	$ 3,378,013
Interest receivable	5,099	6,280
Net overriding royalty interest in oil and gas properties	42,498,034	42,498,034
Accumulated amortization	(34,290,462)	(33,976,766)
Total assets	$ 10,217,177	$ 11,905,561
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 2,009,605	$ 3,384,293
Trust corpus (1,863,590 units of beneficial interest authorized and outstanding)	8,207,572	8,521,268
Total liabilities and trust corpus	$ 10,217,177	$ 11,905,561

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

MESA ROYALTY TRUST
STATEMENTS OF CHANGES IN TRUST CORPUS
(Unaudited)

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
Trust corpus, beginning of period	$ 8,312,437	$ 8,769,240	$ 8,521,268	$ 9,017,067
Distributable income	2,009,605	2,387,134	8,038,751	7,138,484
Distributions to unitholders	(2,009,605)	(2,387,134)	(8,038,751)	(7,138,484)
Amortization of net overriding royalty interest	(104,865)	(123,348)	(313,696)	(371,175)
Trust corpus, end of period	$ 8,207,572	$ 8,645,892	$ 8,207,572	$ 8,645,892

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

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS
(Unaudited)

Note 1 Trust Organization

The Mesa Royalty Trust (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), the predecessor to MESA Inc. On April 30, 1991, MLP sold its interests in the Royalty Properties located in the San Juan Basin field to ConocoPhillips (successor by merger to Conoco, Inc.). ConocoPhillips sold most of its interests in the San Juan Basin Royalty Properties located in Colorado to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP Amoco Company (BP), a subsidiary of BP p.l.c. Until August 7, 1997, MESA Inc. operated the Hugoton Royalty Properties through Mesa Operating Co., a wholly owned subsidiary of MESA Inc. On August 7, 1997, MESA Inc. merged with and into Pioneer Natural Resources Company (Pioneer), formerly a wholly owned subsidiary of MESA Inc., and Parker & Parsley Petroleum Company merged with and into Pioneer Natural Resources USA, Inc. (successor to Mesa Operating Co.), a wholly owned subsidiary of Pioneer (PNR) (collectively, the mergers are referred to herein as the Merger). Subsequent to the Merger, the Hugoton Royalty Properties have been operated by PNR. All of the San Juan Basin Royalty Properties located in New Mexico and a few wells located in Southwest Colorado near the New Mexico border, are operated by ConocoPhillips. Substantially all of the San Juan Basin Royalty Properties located in Colorado are operated by BP. As used in this report, PNR refers to the operator of the Hugoton Royalty Properties, ConocoPhillips refers to the operator of the San Juan Basin Royalty Properties, other than the portion of such properties located in Colorado, and BP refers to the operator of the Colorado San Juan Basin Royalty Properties unless otherwise indicated. 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.

Unless sooner terminated, the Trust Agreement provides that the Trust will terminate in the event that the net revenues fall below $250,000 for two successive years. Net revenues are calculated as royalty and interest income after administrative expenses of the Trust. The Trust may be terminated at any time by a vote of unitholders owning a majority of the Units. The Trust may also be terminated at the expiration of twenty-one years after the death of the last to die of all of the descendants living at the date of execution of this Trust Agreement of Joseph P. Kennedy, late father of the late President of the United States, John F. Kennedy.

Upon termination of the Trust, the Trustee shall sell for cash all the assets. The Trustee shall as promptly as possible distribute the proceeds of any such sales and any other cash according to the respective interests and rights of the unitholders, after paying, satisfying and discharging all the liabilities of the Trust, or, when necessary, setting up reserves in such amounts as Trustee in its discretion deems appropriate for contingent liabilities.

In the event that any property which the Trustee is required to sell is not sold by the Trustee within three years after the termination of the Trust, the Trustee shall cause such property to be sold at public auction to the highest cash bidder. Notice of such sale by auction shall be mailed at least thirty days prior to such sale to each unitholder at his address as it appears upon the books of the Trustee.

Note 2 Basis of Presentation

The accompanying unaudited financial information has been prepared by The Bank of New York Trust Company, N.A. (Trustee), in accordance with the instructions to Form 10-Q. The Bank of New York Trust Company, N.A. is the successor Trustee from JPMorgan Chase Bank, N.A. JPMorgan Chase Bank N.A. was formerly known as The Chase Manhattan Bank and was the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association. The preparation of the financial statements requires estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the financial statements and the reported amounts of income and expenses during the reporting periods. Actual results could differ from those estimates. The Trustee believes such information includes all the disclosures necessary to make the information presented not misleading. The information furnished reflects all adjustments which are, in the opinion of the Trustee, necessary for a fair presentation of the results for the interim periods presented. The financial information should be read in conjunction with the financial statements and notes thereto included in the Trust s Annual Report on Form 10-K for the year ended December 31, 2005.

On April 8, 2006, JPMorgan Chase Bank, N.A. and Bank of New York announced an agreement pursuant to which Bank of New York would acquire JPMorgan Chase s corporate trust business. The transaction was approved and effective October 2, 2006, The Bank of New York Trust Company, N.A. succeeded JPMorgan Chase Bank, N.A. as Trustee.

The Mesa Royalty 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 each month 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 operating and capital costs incurred.

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;

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

(d) Amortization of the net overriding royalty interests, which is calculated on a unit-of-production basis, is charged directly to trust corpus since such amount does not affect distributable income; and

(e) Distributions payable are determined on a monthly basis and are payable to unitholders of record as of the last business day of each month or such other day as the Trustee determines is required to comply with legal or stock exchange requirements. 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 distribution.

This basis for reporting distributable income is thought to be the most meaningful because distributions to the unitholders for a month are based on net cash receipts for such month. However, it will differ from the basis used for financial statements prepared in accordance with accounting principles accepted in the United States of America because under these accounting 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.

Note 3 Legal Proceedings

In August 2006, PNR informed the Trustee that it had reached an agreement to settle claims made in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* which was filed in the 26th Judicial District Court, Stevens County, Kansas. The plaintiffs in this lawsuit are royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of Pioneer Natural Resources Company (Pioneer). The plaintiffs sued a predecessor company to Pioneer USA asserting various claims relating to alleged improper deductions in the calculation of royalties.

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

Pioneer s portion of the cash payment is expected to be approximately $32.7 million. Pioneer will pay the cash portion in two installments. Pioneer has advised the Trustee that the portion of the cash payments net to the Trust s interest was approximately $1.0 million paid on September 30, 2006 and is currently expected to be approximately $0.9 million payable on September 30, 2007. Pioneer USA will initially pay the costs attributable to the Trust s interest but will recover these costs through payments out of future gross proceeds on the Trust s properties. Accordingly, royalty income to the Trust will be significantly reduced until all of these payments, together with any applicable interest as provided under the overriding royalty conveyance of the Trust s properties, are recouped by Pioneer USA.

Pioneer has advised the Trust that under the terms of the settlement agreement, the amounts required to be paid will be reduced if potential participating class members elect not to participate in the settlement by opting out under procedures established by the court. The settlement agreement contains a refund mechanism to address the circumstance where potential participating parties opt out after one of the funding installments is made. Pioneer cannot predict whether opt-outs will occur, or in what magnitude, but in the event that opt-outs occur triggering a refund, Pioneer will advise us of the refund amount attributable to the Trust.

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

Note 4 Federal Income Tax Matters

In a technical advice memorandum dated February 26, 1982, the National Office of the IRS advised the Dallas District Director that the Trust is classifiable as a grantor trust and not as an association taxable as a corporation. Accordingly, no income taxes are provided in the financial statements.

Item 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations.***

The following review of the Trust s financial condition and results of operations should be read in conjunction with the financial statements and notes thereto. The discussion of net production attributable to the Hugoton and San Juan properties represents production volumes that are to a large extent hypothetical as the Trust does not own and is not entitled to any specific production volumes. See Note 7 to the financial statements in the Trust s Annual Report on Form 10-K for the year ended December 31, 2005. Any discussion of actual production volumes represents the hydrocarbons that were produced from the properties in which the Trust has an overriding royalty interest.

The Trust is a passive entity whose purposes are limited to: (1) converting the Royalties to cash, either by retaining them and collecting the proceeds of production (until production has ceased or the Royalties are otherwise terminated) or by selling or otherwise disposing of the Royalties; and (2) distributing such cash, net of amounts for payments of liabilities to the Trust, to the unitholders. The Trust has no sources of liquidity or capital resources other than the revenues, if any, attributable to the Royalties and interest on cash held by the Trustee as a reserve for liabilities or for distribution.

Note Regarding Forward-Looking Statements

This Form 10-Q 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-Q, including without limitation the statements under Management s Discussion and Analysis of Financial Condition and Results of Operations 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-Q and in the Trust s Annual Report on Form 10-K for the year ended December 31, 2005, including under Part I, Item 1A Risk Factors. All subsequent written and oral forward-looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements.

SUMMARY OF ROYALTY INCOME AND AVERAGE PRICES

Royalty income is computed after deducting the Trust s proportionate share of capital costs, operating costs and interest on any cost carryforward from the Trust s proportionate share of Gross Proceeds, as defined in the Royalty conveyance. The following unaudited summary illustrates the net effect of the components of the actual Royalty computation for the periods indicated:

	Three Months Ended September 30, 2006		2005	
	Natural Gas	Oil, Condensate and Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids
The Trust s proportionate share of Gross Proceeds(1)	$ 2,446,591	$ 961,060	$ 2,999,939	$ 767,817
Less the Trust s proportionate share of:				
Capital costs recovered(2)	(312,767)		(270,400)	
Operating costs	(950,360)	(64,977)	(984,829)	(73,069)
Withheld revenues(3)	(56,910)		(42,642)	
Royalty income	$ 1,126,554	$ 896,083	$ 1,702,067	$ 694,748
Average sales price	$ 5.50	$ 42.12	$ 6.14	$ 32.75
	(Mcf)	**(Bbls)**	**(Mcf)**	**(Bbls)**
Net production volumes attributable to the Royalty(4)	204,854	21,276	277,378	21,212

	Nine Months Ended September 30, 2006		2005	
	Natural Gas	Oil, Condensate and Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids
The Trust s proportionate share of Gross Proceeds(1)	$ 9,847,458	$ 2,736,377	$ 8,650,186	$ 2,348,432
Less the Trust s proportionate share of:				
Capital costs recovered(2)	(845,399)		(720,431)	
Operating costs	(2,931,776)	(212,542)	(2,520,359)	(241,663)
Withheld revenues(3)	(518,244)		(335,548)	
Royalty income	$ 5,552,039	$ 2,523,835	$ 5,073,848	$ 2,106,769
Average sales price	$ 7.40	$ 41.03	$ 5.97	$ 32.41
	(Mcf)	**(Bbls)**	**(Mcf)**	**(Bbls)**
Net production volumes attributable to the Royalty(4)	750,106	61,507	849,981	65,004

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

(2) Capital costs recovered represents capital costs incurred during the current or prior periods to the extent that such costs have been recovered by the working interest owners from current period Gross Proceeds.

(3) The Colorado portion of the San Juan Basin Royalty properties have recouped all costs related to the Fruitland Coal drilling program as of December 2004. However, subsequent cumulative earnings totaling $1,101,092 have not yet been remitted to the Trust. Since Royalty income for the Trust is recorded on a cash basis, Royalty income for the quarters ended September 30, 2006 and 2005 of $56,910 and $42,642, respectively, and Royalty income for the nine months ended September 30, 2006 and 2005 of $518,244 and $335,548, respectively cannot be recognized.

(4) Net production volumes attributable to the Royalty are determined by dividing Royalty income by the average sales price received.

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Three Months Ended September 30, 2006 and 2005

	Three Months Ended September 30, 2006	2005
Royalty income	$ 2,022,637	$ 2,396,815
Interest income	5,099	4,340
General and administrative expense	(18,131)	(14,021)
Distributable income	$ 2,009,605	$ 2,387,134
Distributable income per unit	$ 1.0784	$ 1.2809
Units outstanding	1,863,590	1,863,590

The Trust s Royalty income was $2,022,637 in the third quarter of 2006, a decrease of approximately 16% as compared to $2,396,815 in the third quarter of 2005, primarily as a result of lower natural gas prices in the third quarter of 2006 as compared to the third quarter of 2005, partially offset by increased natural gas liquids prices.

The distributable income of the Trust for each period includes the Royalty income received from the working interest owners during such period, plus interest income earned to the date of distribution. Trust administration expenses are deducted in the computation of distributable income. Distributable income for the quarter ended September 30, 2006 was $2,009,605, representing $1.0784 per unit, compared to $2,387,134, representing $1.2809 per unit, for the quarter ended September 30, 2005. Based on 1,863,590 units outstanding for the quarters ended September 30, 2006 and 2005, respectively, the per unit distributions were as follows:

	2006	2005
July	$ 0.3524	$ 0.4563
August	0.3503	0.3984
September	0.3757	0.4262
	$ 1.0784	$ 1.2809

Hugoton Field

Natural gas and natural gas liquids production attributable to the Royalty from the Hugoton field accounted for approximately 56% of the Royalty income of the Trust during the third quarter of 2006.

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 recently including Greely Gas and Oneok Gas Marketing, Inc. PNR has advised the Trust that it expects to continue to market gas production from the Hugoton field under short-term and multi-month contracts. Overall market prices received for natural gas from the Hugoton Royalty Properties were lower in the third quarter of 2006 compared to the third quarter of 2005.

In June 1994, PNR entered into a Gas Transportation Agreement (Gas Transportation Agreement) with Western Resources, Inc. (WRI) for a primary term of five years commencing June 1, 1995. This contract has been continued in effect on a year-to-year basis since June 1, 2001. PNR has extended the contract to June 1, 2007. Pursuant to the Gas Transportation Agreement, WRI has agreed to compress and transport up to 160 MMcf per day of gas and redeliver such gas to PNR at the inlet of PNR s Satanta Plant. PNR agreed to pay WRI a fee of $0.06 per Mcf escalating 4% annually as of June 1, 1996. This Gas Transportation Agreement has been assigned to Kansas Gas Service (Oneok).

Royalty income attributable to the Hugoton Royalty Properties decreased to $1,127,867 in the third quarter of 2006, as compared to $1,277,121 in the third quarter of 2005 primarily due to decreased gas prices received from the Hugoton Royalty Properties. The average price received in the third quarter of 2006 for natural gas and natural gas liquids sold from the Hugoton Royalty Properties was $5.67 per Mcf and $41.17 per barrel, respectively, compared to $6.55 per Mcf and $34.02 per barrel during the same period in 2005. Net production attributable to the Hugoton Royalty was 123,530 Mcf of natural gas and 10,383 barrels of natural gas liquids in the third quarter of 2006 compared to 139,111 Mcf of natural gas and 10,757 barrels of natural gas liquids in the third quarter of 2005. Actual production volumes attributable to the Hugoton properties decreased to 178,166 Mcf of natural gas and 10,389 barrels of natural gas liquids in the third quarter of 2006 as compared to 192,621 Mcf of natural gas and 10,763 barrels of natural gas liquids for the same period in 2005 as a result of natural production decline.

Capital expenditures on these properties were $13,280 in the third quarter of 2006, as compared to $61,585 in the third quarter of 2005. Operating costs were $295,646 in the third quarter of 2006, an increase of approximately 3% as compared to $288,350 in the third quarter of 2005.

San Juan Basin

Royalty income from the San Juan Basin Royalty Properties is calculated and paid to the Trust on a state-by-state basis. Substantially all of the Royalty income from the San Juan Basin Royalty Properties are located in the State of New Mexico. Royalty income from the San Juan Basin Royalty Properties located in the state of New Mexico was $894,770 during the third quarter of 2006 as compared with $1,119,694 in the third quarter of 2005. The average price received in the third quarter of 2006 for natural gas sold from the San Juan Basin Royalty Properties was $5.24 per Mcf and $43.02 per barrel, respectively, compared to $5.72 per Mcf and $31.45 per barrel during the same period in 2005. Net production attributable to the San Juan Basin Royalty was 81,324 Mcf of natural gas and 10,893 barrels of natural gas liquids in the third quarter of 2006 as compared to 138,267 Mcf of natural gas and 10,455 barrels of natural gas liquids in the third quarter of 2005. Actual production volumes attributable to the San Juan Basin properties decreased to 236,843 Mcf of natural gas and 12,404 barrels of natural gas liquids in the third quarter of 2006 as compared to 263,037 Mcf of natural gas and 12,779 barrels of natural gas liquids for the same period in 2005 due to natural declines.

Capital expenditures on these properties were $299,487 in the third quarter of 2006, an increase of 43% as compared to $208,815 in the third quarter of 2005. Operating costs were $580,448 in the third quarter of 2006, an increase of approximately 1% as compared to $577,230 in the third quarter of 2005.

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 represented approximately 72% of the Trust s estimated reserves as of December 31, 2005. Substantially all of the natural gas produced from the San Juan Basin is currently being sold on the spot market. The San Juan Basin Royalty Properties located in Colorado account for less than 5% of the Trust s reserves as of December 31, 2005.

The costs related to the San Juan Basin, Colorado portion were recovered in December 2004. However, subsequent earnings now totaling $1,101,092 based on reports provided by BP have not been remitted by BP. Since Royalty income for the Trust is recorded on a cash basis, the third quarter 2006 earnings of $56,910 cannot be recognized as income for the quarter ended September 30, 2006. The Trustee is currently pursuing payment or a response from BP as to why payments have not been made in a timely manner but cannot predict at this time when payment will be made.

Nine Months Ended September 30, 2006 and 2005

	Nine Months Ended September 30, 2006	2005
Royalty income	$ 8,075,874	$ 7,180,617
Interest income	19,441	11,500
General and administrative expense	(56,564)	(53,633)
Distributable income	$ 8,038,751	$ 7,138,484
Distributable income per unit	$ 4.3136	$ 3.8305
Units outstanding	1,863,590	1,863,590

The Trust s Royalty income was $8,075,874 for the nine months ended September 30, 2006, an increase of approximately 12% as compared to $7,180,617 for the nine months ended September 30, 2005, primarily as a result of higher natural gas and natural gas liquid prices in the first nine months of 2006 as compared to the first nine months of 2005, partially offset by decreased production.

The distributable income of the Trust for each period includes the Royalty income received from the working interest owners during such period, plus interest income earned to the date of distribution. Trust administration expenses are deducted in the computation of distributable income. Distributable income for the nine months ended September 30, 2006 was $8,038,751, representing $4.3136 per unit, compared to $7,138,484, representing $3.8305 per unit, for the nine month ended September 30, 2005.

Hugoton Field

Royalty income attributable to the Hugoton Royalty Properties increased to $4,599,630 for the nine months ended September 30, 2006 from $3,820,772 for the same period in 2005, partially offset by a decrease in natural gas and natural gas liquid production from the Hugoton Royalty Properties. The average price received in the first nine months of 2006 for natural gas and natural gas liquids sold from the Hugoton field was $7.99 per Mcf and $41.60 per barrel, compared to $6.23 per Mcf and $32.91 per barrel during the same period in 2005. Net production attributable to the Hugoton Royalty Properties decreased to 413,228 Mcf of natural gas and 31,200 barrels of natural gas liquids for the nine months ended September 30, 2006 as compared to 432,001 Mcf of natural gas and 34,318 barrels of natural gas liquids for the nine months ended September 30, 2005. Actual production volumes attributable to the Hugoton Royalty Properties decreased to 550,494 Mcf of natural gas and 31,220 barrels of natural gas liquids for the nine months ended September 30, 2006 as compared to 588,179 Mcf of natural gas and 34,310 barrels of natural gas liquids for the same period in 2005 as a result of natural production decline.

The Hugoton capital expenditures were $167,048 during the nine months ended September 30, 2006, an increase of approximately 20% as compared to $139,584 during the nine months ended September 30, 2005. Operating costs were $929,297 during the nine months ended September 30, 2006, an increase of approximately 11% as compared to $837,692 during the nine months ended September 30, 2005.

San Juan Basin

Royalty income from the San Juan Basin Royalty Properties is calculated and paid to the Trust on a state-by-state basis. Substantially all of the Royalty income from the San Juan Basin Royalty Properties are located in the state of New Mexico. The Royalty income was $3,476,244 for the first nine months of 2006 compared to $3,359,845 in the first nine months of 2005. The increase in Royalty income was due primarily to increased natural gas and natural gas liquid prices in the first nine months of 2006 from the San Juan Basin properties. The average price received in the nine months ended September 30, 2006 for natural gas and natural gas liquids sold from the San Juan Basin Royalty Properties was $6.68 per Mcf and $40.45 per barrel, respectively, compared to $5.70 per Mcf and $31.85 per barrel during the same period in 2005. Net production attributable to the San Juan Basin Royalty Properties decreased to 336,878 Mcf of natural gas and 30,307 barrels of natural gas liquids for the nine months ended September 30, 2006 as compared to 417,980 Mcf of natural gas and 30,686 barrels of natural gas liquids for the nine months ended September 30, 2005. Actual production volumes attributable to the San Juan Basin Royalty Properties decreased to 700,915 Mcf of natural gas and 35,565 barrels of natural gas liquids in the nine months ended September 30, 2006 as compared to 772,330 Mcf of natural gas and 38,273 barrels of natural gas liquids for the same period in 2005 as a result of natural production decline.

San Juan-New Mexico capital expenditures were $678,351 during the nine months ended September 30, 2006, an increase of approximately 17% as compared to $580,847 during the nine months ended September 30, 2005. Operating costs were $1,966,468 during the nine months ended September 30, 2006, an increase of approximately 17% as compared to $1,678,880 during the nine months ended September 30, 2005.

The costs related to the San Juan Basin, Colorado portion were recovered in December 2004. However, subsequent earnings now totaling $1,101,092 based on reports provided by BP have not been remitted by BP. Since Royalty income is recorded on a cash basis, earnings of $518,244 cannot be recognized as income for the nine months ended September 30, 2006. The Trustee is currently pursuing payment or a response from BP as to why payments have not been made in a timely manner but cannot predict at this time when payment will be made.

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk.***

The Trust does not utilize market risk sensitive instruments. However, see the discussion of marketing by the working interest owners above.

Item 4. ***Controls and Procedures*.**

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the Exchange Act), is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated by the working interest owners to The Bank of New York Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust s periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Trustee carried out an evaluation of the Trustee s disclosure controls and procedures. Mike Ulrich, as Vice President of the Trustee, has concluded that these controls and procedures were effective at that time.

Due to the contractual arrangements of (i) the Trust Indenture and (ii) the rights of the Partnership under the Conveyance regarding information furnished by the working interest owners, the Trustee relies on information provided by the working interest owners, including (i) the status of litigation, (ii) historical operating data, plans for future operating and capital expenditures, and reserve information, (iii) information relating to projected production, and (iv) conclusions regarding reserves by their internal reserve engineers or other experts in good faith. See Part I, Item 1A. Risk Factors None of the Trustee, the Trust nor its unitholders control the operation or development of the Royalty Properties and have little influence over operation or development and The Trustee relies upon the working interests owners for information regarding the Royalty Properties in the Trust s Annual Report on Form 10-K for the year ended December 31, 2005 for a description of certain risks relating to these arrangements and reliance.

Changes in Internal Control over Financial Reporting. In connection with the evaluation by the Trustee of changes in internal control over financial reporting of the Trust that occurred during the Trust s last fiscal quarter, no change in the Trust s internal control over financial reporting was identified that has materially affected, or is reasonably likely to materially affect, the Trust s internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. ***Legal Proceedings*.**

In August 2006, PNR informed the Trustee that it had reached an agreement to settle claims made in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* which was filed in the 26th Judicial District Court, Stevens County, Kansas. The plaintiffs in this lawsuit are royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of Pioneer Natural Resources Company (Pioneer). The plaintiffs sued a predecessor company to Pioneer USA asserting various claims relating to alleged improper deductions in the calculation of royalties.

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

Pioneer s portion of the cash payment is expected to be approximately $32.7 million. Pioneer will pay the cash portion in two installments. Pioneer has advised the Trustee that the portion of the cash payments net to the Trust s interest was approximately $1.0 million paid on September 30, 2006 and is currently expected to be approximately $0.9 million payable on September 30, 2007. Pioneer USA will initially pay the costs attributable to the Trust s interest but will recover these costs through payments out of future gross proceeds on the Trust s properties. Accordingly, royalty income to the Trust will be significantly reduced until all of these payments, together with any applicable interest as provided under the overriding royalty conveyance of the Trust s properties, are recouped by Pioneer USA.

Pioneer has advised the Trust that under the terms of the settlement agreement, the amounts required to be paid will be reduced if potential participating class members elect not to participate in the settlement by opting out under procedures established by the court. The settlement agreement contains a refund mechanism to address the circumstance where potential participating parties opt out after one of the funding installments is made. Pioneer cannot predict whether opt-outs will occur, or in what magnitude, but in the event that opt-outs occur triggering a refund, Pioneer will advise us of the refund amount attributable to the Trust.

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

Item 1A. ***Risk Factors.***

There have not been any material changes from risk factors previously disclosed in response to Item 1A. to Part 1 of the Trust s Form 10-K for the year ended December 31, 2005.

Item 6. ***Exhibits.***

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. The Bank of New York Trust Company, N.A. is the successor trustee from JPMorgan Chase Bank, N.A. effective in October 2006. JPMorgan Chase Bank, N.A. was formerly known as The Chase Manhattan Bank and was successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association.)

		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)	1-07884	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)	1-07884	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)	1-07884	4(e)
31	Rule 13a-14(a)/15d-14(a) Certification		
32	Section 1350 Certification		

SIGNATURES

Pursuant to the requirements 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 Bank of New York Trust Company, N.A., as Trustee
By:	
	Mike Ulrich
	Vice President

Date: November 9, 2006

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.