Hugoton Royalty Trust

2011

Annual Report and Form 10-K

Glossary of Terms

Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Mcf	Thousand cubic feet (of natural gas)
MMBtu	One million British Thermal Units, a common energy measurement
Net Proceeds	Gross proceeds received by XTO Energy from sale of production from the underlying properties, less applicable costs, as defined in the net profits interest conveyances.
Net Profits Income	Net proceeds multiplied by the net profits percentage of 80%, which is paid to the trust by XTO Energy. "Net profits income" is referred to as "royalty income" for tax reporting purposes.
Net Profits Interest	An interest in an oil and gas property measured by net profits from the sale of production, rather than a specific portion of production. The following defined net profits interests were conveyed to the trust from the underlying properties. *80% net profits interests* – interests that entitle the trust to receive 80% of the net proceeds from the underlying properties.
Underlying Properties	XTO Energy's interest in certain oil and gas properties from which the net profits interests were conveyed. The underlying properties include working interests in predominantly gas-producing properties located in Kansas, Oklahoma and Wyoming.
Working Interest	An operating interest in an oil and gas property that provides the owner a specified share of production that is subject to all production expense and development costs.

Units of Beneficial Interest

The units of beneficial interest in the trust began trading on the New York Stock Exchange on April 9, 1999 under the symbol "HGT." The following are the high and low unit sales prices and total cash distributions per unit paid by the trust during each quarter of 2011 and 2010:

	Sales Price		Distributions
2011	**High**	**Low**	**per Unit**
First Quarter	**$24.67**	**$20.31**	**$0.323500**
Second Quarter	**24.25**	**21.35**	**0.360069**
Third Quarter	**23.84**	**19.51**	**0.383334**
Fourth Quarter	**22.53**	**18.71**	**0.327221**
			$1.394124
2010			
First Quarter	$18.65	$15.00	$0.414128
Second Quarter	22.13	16.58	0.468323
Third Quarter	21.39	18.01	0.363184
Fourth Quarter	21.65	19.39	0.305065
			$1.550700

At December 31, 2011, there were 40,000,000 units outstanding and approximately 934 unitholders of record.

To Unitholders:

We are pleased to present the 2011 Annual Report on Form 10-K of the Hugoton Royalty Trust as filed with the Securities and Exchange Commission. This report contains important information about the trust's net profits interests, including information provided to the trustee by XTO Energy.

For the year ended December 31, 2011, net profits income totaled $56,565,368. After adding interest income of $1,155 and deducting trust administration expense of $801,563, distributable income was $55,764,960 or $1.394124 per unit. Net profits income and distributions were 10% lower than 2010 amounts primarily because of decreased oil and gas production, partially offset by higher oil prices.

Natural gas prices averaged $4.73 per Mcf for 2011, relatively flat compared to the 2010 average price of $4.72 per Mcf. The average 2011 oil price was $90.07 per Bbl, 22% higher than the 2010 average price of $73.77 per Bbl.

Gas sales volumes from the underlying properties for 2011 were 21,693,139 Mcf, or 59,433 Mcf per day, a decrease of 10% from 65,959 Mcf per day in 2010. Oil sales volumes from the underlying properties were 248,739 Bbls, or 681 Bbls per day in 2011, a decrease of 7% from 731 Bbls per day in 2010. For further information on sales volumes and product prices, see "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" under Item 7 of the accompanying Form 10-K.

As of December 31, 2011, proved reserves for the underlying properties were estimated by independent engineers to be 289.9 Bcf of natural gas and 2.7 million Bbls of oil. Natural gas reserves for the underlying properties declined 25.1 Bcf and oil reserves for the underlying properties declined approximately 0.1 million Bbls primarily due to current year production and negative revisions to gas reserves related primarily to increased future costs, partially offset by positive revisions to oil reserves from higher oil prices. Based on an allocation of these reserves, proved reserves attributable to the net profits interests were estimated to be 126.3 Bcf of natural gas and 1.3 million Bbls of oil. Estimated gas and oil reserves attributable to the net profits interests decreased from previously reported reserves at year-end 2010 as current year production and

To Unitholders: Continued

negative revisions to gas reserves related primarily to increased future costs were partially offset by positive revisions to oil reserves due to higher oil prices. All reserve information prepared by independent engineers has been provided to the trustee by XTO Energy.

Estimated future net cash flows from proved reserves of the net profits interests at December 31, 2011 were $658 million. Using an annual discount factor of 10%, the present value of estimated future net cash flows at December 31, 2011 was $335 million. Proved reserve estimates and related future net cash flows have been determined based on a 12-month average gas price of $4.67 per Mcf and a 12-month average oil price of $92.92 per Bbl, based on the first-day-of-the-month price for each month in the period, and year end costs. Other guidelines used in estimating proved reserves, as prescribed by the Financial Accounting Standards Board, are described in Note 10 to Financial Statements under Item 8, "Financial Statements and Supplementary Data" of the accompanying Form 10-K. The present value of estimated future net cash flows is computed based on SEC guidelines and is not necessarily representative of the market value of trust units.

As disclosed in the tax instructions provided to unitholders in February 2012, trust distributions are considered portfolio income, rather than passive income. Unitholders should consult their tax advisors for further information.

HUGOTON ROYALTY TRUST
BY: U.S. TRUST, BANK OF AMERICA
PRIVATE WEALTH MANAGEMENT, TRUSTEE

BY: NANCY G. WILLIS
VICE PRESIDENT

March 21, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011 **Commission file number 1-10476**

Hugoton Royalty Trust

(Exact name of registrant as specified in the Hugoton Royalty Trust Indenture)

Texas	**58-6379215**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

U.S. Trust, Bank of America
Private Wealth Management
Trustee
P.O. Box 830650
Dallas, Texas 75283-0650
(Address of principal executive offices) (Zip Code)

Registrant's telephone number including area code:
(877) 228-5083

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

Title of each class	**Name of each exchange on which registered**
Units of Beneficial Interest	New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

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

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

The aggregate market value of the units of beneficial interest of the trust, based on the closing price on the New York Stock Exchange as of June 30, 2011 (the last business day of its most recently completed second fiscal quarter), held by non-affiliates of the registrant on that date was approximately $910 million.

At February 16, 2012, there were 40,000,000 units of beneficial interest of the trust outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Listed below is the only document parts of which are incorporated herein by reference and the parts of this report into which the document is incorporated:

None

HUGOTON ROYALTY TRUST
2011 ANNUAL REPORT ON FORM 10-K

TABLE OF CONTENTS

		Page
	Glossary of Terms	1
	Part I	
Item 1.	Business	2
Item 1A.	Risk Factors	3
Item 1B.	Unresolved Staff Comments	8
Item 2.	Properties	8
Item 3.	Legal Proceedings	17
Item 4.	Mine Safety Disclosures	18
	Part II	
Item 5.	Market for Units of the Trust, Related Unitholder Matters and Trust Purchases of Units	19
Item 6.	Selected Financial Data	19
Item 7.	Trustee's Discussion and Analysis of Financial Condition and Results of Operations	20
Item 7A.	Quantitative and Qualitative Disclosures about Market Risk	26
Item 8.	Financial Statements and Supplementary Data	27
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	43
Item 9A.	Controls and Procedures	43
Item 9B.	Other Information	43
	Part III	
Item 10.	Directors, Executive Officers and Corporate Governance	44
Item 11.	Executive Compensation	44
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	44
Item 13.	Certain Relationships and Related Transactions, and Director Independence	45
Item 14.	Principal Accountant Fees and Services	45
	Part IV	
Item 15.	Exhibits and Financial Statement Schedules	46

HUGOTON ROYALTY TRUST

GLOSSARY OF TERMS

The following are definitions of significant terms used in this Annual Report on Form 10-K:

Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Mcf	Thousand cubic feet (of natural gas)
MMBtu	One million British Thermal Units, a common energy measurement
net proceeds	Gross proceeds received by XTO Energy from sale of production from the underlying

The market price for the trust units may not reflect the value of the net profits interests held by the trust.

The public trading price for the trust units tends to be tied to the recent and expected levels of cash distributions on the trust units. The amounts available for distribution by the trust vary in response to numerous factors outside the control of the trust or XTO Energy, including prevailing prices for oil and natural gas produced from the underlying properties. The market price of the trust units is not necessarily indicative of the value that the trust would realize if the net profits interests were sold to a third party buyer. In addition, such market price is not necessarily reflective of the fact that, since the assets of the trust are depleting assets, a portion of each cash distribution paid on the trust units should be considered by investors as a return of capital, with the remainder being considered as a return on investment. There is no guarantee that distributions made to a unitholder over the life of these depleting assets will equal or exceed the purchase price paid by the unitholder.

Oil and natural gas prices fluctuate due to a number of uncontrollable factors, and any decline will adversely affect the net proceeds payable to the trust and trust distributions.

The trust's monthly cash distributions are highly dependent upon the prices realized from the sale of natural gas and, to a lesser extent, oil. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the trust and XTO Energy. Factors that contribute to price fluctuations include instability in oil-producing regions, worldwide economic conditions, weather conditions, the supply and price of domestic and foreign oil, natural gas and natural gas liquids, consumer demand, the price and availability of alternative fuels, the proximity to, and capacity of, transportation facilities and the effect of worldwide energy conservation measures. Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices in the long term. Lower oil and natural gas prices may reduce the amount of oil and natural gas that is economic to produce and will reduce net profits available to the trust. The volatility of energy prices reduces the predictability of future cash distributions to trust unitholders.

Higher production expense and/or development costs, without concurrent increases in revenue, will directly decrease the net proceeds payable to the trust.

Production expense and development costs are deducted in the calculation of the trust's share of net proceeds. Accordingly, higher or lower production expense and development costs, without concurrent changes in revenue, will directly decrease or increase the amount received by the trust. If development costs and production expense for underlying properties in a particular state exceed the production proceeds from the properties (as was the case with respect to the properties underlying the Kansas net profits interests in October and November 2009), the trust will not receive net proceeds for those properties until future proceeds from production in that state exceed the total of the excess costs plus accrued interest during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs.

Proved reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions could cause the quantities and net present value of the reserves to be overstated.

Estimating proved oil and gas reserves is inherently uncertain. Petroleum engineers consider many factors and make assumptions in estimating reserves and future net cash flows. Those factors and assumptions include historical production from the area compared with production rates from similar producing areas, the effects of governmental regulation, assumptions about future commodity prices, production expense and development costs, taxes and capital expenditures, the availability of enhanced recovery techniques and relationships with landowners, working interest partners, pipeline companies and others. Lower oil and gas prices generally cause lower estimates of proved reserves. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variances could be material. Because the trust owns net profits interests, it does not own a specific percentage of the oil and gas reserves. Estimated proved reserves for the net profits interests are based on estimates of reserves for the underlying properties and an allocation method that considers estimated future net proceeds and oil and gas

prices. Because trust reserve quantities are determined using an allocation formula, increases or decreases in oil and gas prices can significantly affect estimated reserves of the net profits interests.

Operational risks and hazards associated with the development of the underlying properties may decrease trust distributions.

There are operational risks and hazards associated with the production and transportation of oil and natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of oil or natural gas, releases of other hazardous materials, mechanical failures, cratering, and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, damage to the environment or natural resources, or cleanup obligations. The operation of oil and gas properties is also subject to various laws and regulations. Non-compliance with such laws and regulations could subject the operator to additional costs, sanctions or liabilities. The uninsured costs resulting from any of the above or similar occurrences could be deducted as a production expense or development cost in calculating the net proceeds payable to the trust, and would therefore reduce trust distributions by the amount of such uninsured costs.

Cash held by the trustee is not fully insured by the Federal Deposit Insurance Corporation, and future royalty income may be subject to risks relating to the creditworthiness of third parties.

Currently, cash held by the trustee as a reserve for liabilities and for the payment of expenses and distributions to unitholders is invested in Bank of America, N.A. certificates of deposit which are backed by the good faith and credit of Bank of America, N.A., but are only insured by the Federal Deposit Insurance Corporation up to $250,000. Each unitholder should independently assess the creditworthiness of Bank of America, N.A. For more information about the credit rating of Bank of America, N.A., please refer to its periodic filings with the SEC. The trust does not lend money and has limited ability to borrow money, which the trustee believes limits the trust's risk from the currently tight credit markets. The trust's future royalty income, however, may be subject to risks relating to the creditworthiness of the operators of the underlying properties and other purchasers of crude oil and natural gas produced from the underlying properties, as well as risks associated with fluctuations in the price of crude oil and natural gas. Information contained in Bank of America N.A.'s periodic filings with the SEC is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report or any other filing that the trust makes with the SEC.

Trust unitholders and the trustee have no influence over the operations on, or future development of, the underlying properties.

Neither the trustee nor the trust unitholders can influence or control the operation or future development of the underlying properties. The failure of an operator to conduct its operations or discharge its obligations in a proper manner could have an adverse effect on the net proceeds payable to the trust. Although XTO Energy and other operators of the underlying properties must adhere to the standard of a prudent operator, they are under no obligation to continue operating the properties. Neither the trustee nor trust unitholders have the right to replace an operator.

The assets of the trust represent interests in depleting assets and, if XTO Energy or any other operators developing the underlying properties do not perform additional successful development projects, the assets may deplete faster than expected. Eventually, the assets of the trust will cease to produce in commercial quantities and the trust will cease to receive proceeds from such assets.

The net proceeds payable to the trust are derived from the sale of hydrocarbons from depleting assets. The reduction in proved reserve quantities is a common measure of the depletion. Future maintenance and development projects on the underlying properties will affect the quantity of proved reserves and can offset the reduction in proved reserves. The timing and size of these projects will depend on the market prices of oil and natural gas. If the operator(s) of the properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the trust. Because the net proceeds payable to the trust are derived from the sale of hydrocarbons from depleting assets, the portion of

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

Terrorism and continued geopolitical hostilities could adversely affect trust distributions or the market price of the trust units.

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

XTO Energy may transfer its interest in the underlying properties without the consent of the trust or the trust unitholders.

XTO Energy may at any time transfer all or part of its interest in the underlying properties to another party. Neither the trust nor the trust unitholders are entitled to vote on any transfer of the properties underlying the trust's net profits interests, and the trust will not receive any proceeds of any such transfer. Following any transfer, the transferred property will continue to be subject to the net profits interests of the trust, but the calculation, reporting and remitting of net proceeds to the trust will be the responsibility of the transferee.

XTO Energy or any other operator of any underlying property may abandon the property, thereby terminating the related net profits interest payable to the trust.

XTO Energy or any other operator of the underlying properties, or any transferee thereof, may abandon any well or property without the consent of the trust or the trust unitholders if they reasonably believe that the well or property can no longer produce in commercially economic quantities. This could result in the termination of the net profits interest relating to the abandoned well or property.

The net profits interests can be sold and the trust would be terminated.

The trust may sell the net profits interests if the holders of 80% or more of the trust units approve the sale or vote to terminate the trust. The trust will terminate if it fails to generate gross proceeds from the underlying properties of at least $1,000,000 per year over any consecutive two-year period. Sale of all of the net profits interests will terminate the trust. The net proceeds of any sale must be for cash with the proceeds promptly distributed to the trust unitholders.

Trust unitholders have limited voting rights and have limited ability to enforce the trust's rights against XTO Energy or any other operator of the underlying properties.

The voting rights of a trust unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of trust unitholders or for an annual or other periodic re-election of the trustee. Additionally, trust unitholders have no voting rights in XTO Energy or Exxon Mobil Corporation.

The trust indenture and related trust law permit the trustee and the trust to sue XTO Energy or any other operator of the underlying properties to compel them to fulfill the terms of the conveyance of the net profits interests. If the trustee does not take appropriate action to enforce provisions of the conveyance, the recourse of the trust unitholders would likely be limited to bringing a lawsuit against the trustee to compel the trustee to take specified actions. Trust unitholders probably would not be able to sue XTO Energy or any other operator of the underlying properties.

Financial information of the trust is not prepared in accordance with U.S. GAAP.

The financial statements of the trust are prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles, or U.S. GAAP. Although this basis of accounting is permitted for royalty trusts by the Securities and Exchange Commission, the financial statements of the trust differ from U.S. GAAP financial statements because net profits income is not accrued in the month of production, expenses are not recognized when incurred and cash reserves may be established for certain contingencies that would not be recorded in U.S. GAAP financial statements.

The limited liability of trust unitholders is uncertain.

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

Drilling oil and natural gas wells is a high-risk activity and subjects the trust to a variety of factors that it cannot control.

Drilling oil and natural gas wells involves numerous risks, including the risk that commercially productive oil and natural gas reservoirs are not encountered. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause drilling activities to be unsuccessful. In addition, there is often uncertainty as to the future cost or timing of drilling, completing and operating wells. Further, development activities may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- restricted access to land for drilling or laying pipeline;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions; and
- costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and equipment.

While these risks do not expose the trust to liabilities of the drilling contractor or operator of the well, they can reduce net proceeds payable to the trust and trust distributions by decreasing oil and gas revenues or increasing production expense or development costs from the underlying properties. Furthermore, these risks may cause the costs of development activities on the underlying properties to exceed the revenues therefrom, thereby reducing net proceeds payable to the trust and trust distributions.

The underlying properties are subject to complex federal, state and local laws and regulations that could adversely affect net proceeds payable to the trust and trust distributions.

Extensive federal, state and local regulation of the oil and natural gas industry significantly affects operations on the underlying properties. In particular, oil and natural gas development and production are subject to stringent environmental regulations. These regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning oil and natural gas wells and other related facilities, which costs could reduce net proceeds payable to the trust and trust distributions. These regulations may become more demanding in the future.

Item 1B. ***Unresolved Staff Comments***

As of December 31, 2011, the trust did not have any unresolved Securities and Exchange Commission staff comments.

Item 2. ***Properties***

The net profits interests are the principal asset of the trust. The trustee cannot acquire any other assets, with the exception of certain short-term investments as specified under Item 1, Business. The trustee may sell or otherwise dispose of all or any part of the net profits interests if approved by at least 80% of the unitholders, or upon termination of the trust. Otherwise, the trust may only sell up to 1% of the value of the net profits interests in any calendar year, pursuant to notice from XTO Energy of its desire to sell the related underlying properties. Any such sale must be for cash with the proceeds promptly distributed to the unitholders. All the underlying properties are currently owned by XTO Energy. XTO Energy may sell all or any portion of the underlying properties at any time, subject to and burdened by the net profits interests.

The underlying properties are predominantly gas-producing properties with established production histories in the Hugoton area of Oklahoma and Kansas, the Anadarko Basin of Oklahoma and the Green River Basin of Wyoming. The average reserve-to-production index for the underlying properties as of December 31, 2011 is approximately 14 years. This index is calculated using total proved reserves and estimated 2012 production for the underlying properties. The projected 2012 production is from proved developed producing reserves as of December 31, 2011. Based on estimated future net cash flows at 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period, the proved reserves of the underlying properties are approximately 84% natural gas and 16% oil. XTO Energy operates approximately 95% of the underlying properties.

Because the underlying properties are working interests, production expense, development costs and overhead are deducted in calculating net profits income. As a result, net profits income is affected by the level of maintenance and development activity on the underlying properties. See Trustee's Discussion and Analysis of Financial Condition and Results of Operations, under Item 7. Total 2011 development costs deducted for the underlying properties were $9 million, an increase of 21% from the prior year. XTO Energy has informed the trustee that total 2012 budgeted development costs for the underlying properties are between $8 million and $9 million.

Significant Properties

Hugoton Area

Natural gas was discovered in the Hugoton area in 1922. With an estimated five million productive acres covering parts of Texas, Oklahoma and Kansas, the Hugoton area is one of the largest domestic natural gas producing areas. During 2011, daily sales volumes from the underlying properties in the Hugoton area averaged approximately 16,900 Mcf of gas and 81 Bbls of oil.

Most of the production from the underlying properties in the Hugoton area is from the Chase formation. XTO Energy has informed the trustee that it has begun to develop other formations that underlie the 79,500 net acres held by production by the Chase formation wells, which include the Council Grove, Morrow, Chester and St. Louis formations. These formations are characterized by both oil and gas production from a variety of structural and stratigraphic traps. Since 2003, XTO Energy has drilled wells to these formations and plans to continue this development program in 2012.

Within this area, XTO Energy did not drill any wells but did perform 5 workovers in 2011. XTO Energy has informed the trustee that it plans to drill up to 2 new wells and perform up to 20 workovers during 2012.

XTO Energy's future development plans for the underlying properties in the Hugoton area include:

- additional compression to lower line pressures,
- installing artificial lift,

- opening new producing zones in existing wells,
- restimulating producing intervals in existing wells utilizing new technology,
- deepening existing wells to new producing zones, and
- drilling additional wells.

XTO Energy delivers most of its Hugoton gas production to a gathering and processing system owned by a subsidiary. Most of the gas is sold under the terms of a contract that was entered into in March 1996, predating the existence of the trust. This system collects the majority of its throughput from underlying properties, which, in recent months, has been approximately 11,500 Mcf per day. The gathering subsidiary purchases the gas from XTO Energy at the wellhead, gathers and transports the gas to its plant, and treats and processes the gas at the plant. The gathering subsidiary has agreed to use its best efforts to purchase all gas produced by XTO Energy from the wells that are subject to the contract, but the gathering subsidiary is not obligated to purchase gas in excess of its market requirements. The gathering subsidiary has been taking all of the gas produced for over ten years. The gathering subsidiary pays XTO Energy for wellhead volumes at a price of 80% to 85% of the net residue price received by XTO Energy's marketing affiliate, which amount is adjusted for the BTU content of the gas. This affiliate currently sells the residue to a pipeline at a price based on a monthly pipeline index less actual third party fees. The term of these contracts can vary by contract, but in general the contracts, after an initial stated period, renew on a monthly basis unless either party gives notice of termination. If either party to the contracts fails to perform under the contract, the contract may be terminated if written notice is given of the breach and the breaching party fails to cure the breach within a specified period. The March 1996 contract has an annual price renegotiation term under which either party can request that the price provided under the contract be renegotiated. Neither party has requested that the price be renegotiated. XTO Energy does not anticipate that the terms of the contracts will be renegotiated.

Other Hugoton gas production is sold under a third party contract that remains in effect for the life of the lease. Under the contract, XTO Energy receives 74.5% of the net proceeds received by the buyer from the sale of the residue gas and liquids produced from certain underlying properties. The residue gas net proceeds are based upon the weighted average price of the gas sold by the buyer at its facilities, and the liquids net proceeds are based upon an average daily index sales price, less transportation, processing and storage fees incurred by the buyer. The buyer agrees to use its best efforts to take all of the gas produced, subject to its market requirements. The buyer has been taking all of the gas produced for over ten years.

Anadarko Basin

Oil and gas accumulations were discovered in the Anadarko Basin of western Oklahoma in 1945. XTO Energy is one of the largest producers in the Ringwood, Northwest Okeene and Cheyenne Valley fields of Major County, the Northeast Cedardale field of Woodward County and the Elk City field of Beckham County, the principal producing regions of the underlying properties in the Anadarko Basin. Daily sales volumes from the underlying properties in the Anadarko Basin averaged 26,500 Mcf of gas and 568 Bbls of oil in 2011.

The fields in the Major County area are characterized by oil and gas production from a variety of structural and stratigraphic traps. Productive zones include the Oswego, Red Fork, Inola, Chester, Manning, Mississippian, Hunton and Arbuckle formations. Within this area, XTO Energy drilled 1 gross (1.0 net) well and performed 35 workovers in 2011. XTO Energy has informed the trustee that it plans to drill 1 new well and perform up to 14 workovers in Major County during 2012.

The fields within Woodward County are characterized primarily by gas production from a variety of structural and stratigraphic traps. Productive zones include the Cottage Grove, Oswego, Chester and Mississippian formations. Within this area, XTO Energy did not drill any wells or perform any workovers in 2011. XTO Energy has informed the trustee that it does not plan to drill any new wells but may perform up to 4 workovers in Woodward County during 2012.

The Elk City field on the eastern edge of Beckham County produces oil and gas from a structural anticline with stratigraphic trapping features. Production zones include the Hoxbar, Atoka and Morrow formations. Within this area,

XTO Energy did not drill any wells but did perform 9 workovers in 2011. XTO Energy has informed the trustee that it plans to drill 1 new well and perform up to 6 workovers within the Elk City field during 2012.

XTO Energy plans to further develop the underlying properties in the Anadarko Basin primarily through:

- mechanical stimulation of existing wells,
- installing artificial lift,
- opening new producing zones in existing wells,
- deepening existing wells to new producing zones, and
- drilling additional wells.

A gathering subsidiary of XTO Energy operates a 300-mile gathering system and pipeline in the Major County area. The gathering subsidiary and a third-party processor purchase natural gas produced at the wellhead from XTO Energy and other producers in the area under various agreements, most of which were entered into in the 1960's and 1970's, and which include life-of-production terms such that the contracts will continue until there is no further production from the underlying properties, unless the production declines so that it is no longer economical to take the gas. The gathering subsidiary and the third-party processor are required to take certain minimum volumes of the gas produced but have been taking all of the volumes produced for over ten years. The gathering subsidiary gathers and transports the gas to a third-party processor, which processes the gas and pays XTO Energy and other producers for at least 50% of the liquids processed based upon a weighted average sales price less transportation charges, which price may vary in the event of inadequate markets. After the gas is processed, the gathering subsidiary transports the gas via a residue pipeline to a connection with an interstate pipeline. The gathering subsidiary sells the residue gas to the marketing subsidiary of XTO Energy based upon a weighted average price, which price will vary monthly based upon market conditions. The gathering subsidiary pays this price to XTO Energy less a compression and gathering fee of approximately $0.31 per Mcf of residue gas. This gathering fee was previously approved by the Federal Energy Regulatory Commission when the gathering subsidiary was regulated and is unlikely to change. During 2011, the gathering system collected approximately 10,500 Mcf per day, approximately 50% of which XTO Energy operates. Estimated capacity of the gathering system is 24,000 Mcf per day. The gathering subsidiary also provides contract operating services to properties in Woodward County, collecting approximately 9,500 Mcf per day, for an average fee of approximately $0.05 per Mcf. The fee is subject to an annual price renegotiation under which either party can request that the price provided under the contract be renegotiated. The contract continues on a yearly basis, and it is subject to termination upon written notice prior to its annual renewal or in the event the parties fail to agree upon a pricing renegotiation. XTO Energy also sells gas directly to its marketing subsidiary under a month-to-month contract, which then sells the gas to third parties. The price paid to XTO Energy is based upon the weighted average price of several published indices, which price varies upon market conditions but does not include a deduction for any marketing fees. The price paid by the marketing affiliate includes a deduction for any transportation fees charged by the third party. Neither party has a firm obligation to sell or purchase any specific minimum quantity of gas.

Green River Basin

The Green River Basin is located in southwestern Wyoming. Natural gas was discovered in the Fontenelle field of the Green River Basin in the early 1970's. The producing reservoirs are the Frontier, Baxter and Dakota sandstones.

Daily 2011 sales volumes from the underlying properties in the Fontenelle field averaged 16,000 Mcf of natural gas and 32 Bbls of oil. In 2011, XTO Energy did not drill any wells but did perform 1 workover. XTO Energy has advised the trustee that it does not plan to drill any new wells but may perform up to 4 workovers in the Green River Basin during 2012. XTO Energy has advised the trustee that it is continuing its efforts to reduce pipeline pressure which has shown potential for increasing production and extending field life in the Fontenelle Field.

Potential development activities for the underlying properties in this area include:

- installing artificial lift,
- restimulating producing intervals utilizing new technology,

- additional compression to lower line pressures, and
- opening new producing zones in existing wells.

XTO Energy markets the gas produced from the Fontenelle field and nearby properties under various marketing arrangements. Under the agreement covering the majority of the gas sold, XTO Energy compresses the gas on the lease, transports it off the lease and compresses the gas again prior to entry into the gas plant pipeline. The pipeline transports the gas to the gas plant, where the gas is processed, then redelivered to XTO Energy. The owner of the gas plant and related pipeline charges XTO Energy for operational fuel and processing and has agreed to accept certain volumes, which amounts can be adjusted by the owner. The owner may be able to cease taking volumes if it has valid unaddressed concerns regarding the creditworthiness of XTO Energy. In 2011, the fuel charge was 2.00% of the volumes produced and the processing fee was approximately $0.11 per MMBtu. These charges are adjusted annually based upon a published governmental economic index, and the contract renews on a year-to-year basis. XTO Energy transports and sells this gas directly to the markets based on a spot sales price on a month-to-month term, and the volumes to be sold are generally determined upon a monthly basis. These contracts may be terminated by either party if there are credit issues with the other party. The gas not sold under the above arrangement may be gathered and sold under a similar arrangement on a month-to-month term where the fee is approximately $0.18 per MMBtu and is adjusted annually. The amount of gas that the gatherer is required to gather is limited to certain maximum volumes, and the gatherer may be able to cease taking volumes if it has valid unaddressed concerns regarding the creditworthiness of XTO Energy. Alternatively, the gas may be sold under a contract where XTO Energy directly sells the gas to a third party on the lease at an adjusted index price, which price varies upon market conditions. The contract continues on a month-to-month basis, and the buyer is obligated to make a good faith effort to purchase a minimum 90% of the gas nominated by buyer for purchase. Condensate is sold to an independent third party at market rates on a month-to-month basis. The purchaser accepts all condensate delivered at the lease, but either party may suspend performance of the contract if there are credit issues with the other party.

Producing Acreage, Drilling and Well Counts

For the following data, “gross” refers to the total wells or acres on the underlying properties in which XTO Energy owns a working interest and “net” refers to gross wells or acres multiplied by the percentage working interest owned by XTO Energy. Although many of XTO Energy’s wells produce both oil and gas, a well is categorized as an oil well or a gas well based upon the ratio of oil to natural gas production. Operated wells are managed by XTO Energy, while nonoperated wells are managed by others.

The underlying properties are interests in developed properties located primarily in gas producing regions of Kansas, Oklahoma and Wyoming. The following is a summary of the approximate producing acreage of the underlying properties at December 31, 2011. Undeveloped acreage is not significant.

	Gross	Net
Hugoton Area	212,724	197,623
Anadarko Basin	173,159	134,080
Green River Basin	37,912	28,626
Total	423,795	360,329

The following is a summary of the producing wells on the underlying properties as of December 31, 2011:

	Operated Wells		Nonoperated Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Gas	1,232.0	1,094.7	295.0	66.7	1,527.0	1,161.4
Oil	36.0	32.1	5.0	0.9	41.0	33.0
Total	1,268.0	1,126.8	300.0	67.6	1,568.0	1,194.4

The following is a summary of the number of wells drilled on the underlying properties during the years indicated. During 2011, 1 exploratory dry hole (0.0 net) was drilled on the underlying properties. No exploratory wells were drilled on the underlying properties in 2010 or 2009; all other wells drilled were developmental. There was 1 gross (0.6 net) well in process of drilling at December 31, 2011.

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Completed gas wells	3	1.5	3	2.7	9	5.1
Completed oil wells	—	—	—	—	1	1.0
Dry wells	1	—	—	—	—	—
Total(a)	4	1.5	3	2.7	10	6.1

(a) Included in totals are 3 gross (0.5 net) wells in 2011, zero wells in 2010 and 5 gross (1.2 net) wells in 2009, drilled on nonoperated interests.

Estimated Proved Reserves and Future Net Cash Flows

The following are proved reserves of the underlying properties, as estimated by independent engineers, and proved reserves and future net cash flows from proved reserves of the net profits interests, based on an allocation of these reserves, at December 31, 2011:

	Underlying Properties		Net Profits Interests			
	Proved Reserves[a]		Proved Reserves[a][b]		Future Net Cash Flows from Proved Reserves[a][c]	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Undiscounted	Discounted
(in thousands)						
Oklahoma	191,386	2,509	90,801	1,191	$517,710	$259,728
Wyoming	76,161	83	25,282	28	90,444	47,214
Kansas	22,362	147	10,179	68	49,686	28,011
TOTAL	289,909	2,739	126,262	1,287	$657,840	$334,953

(a) Based on 12-month average oil price of $92.92 per Bbl and $4.67 per Mcf for gas, based on the first-day-of-the-month price for each month in the period. Discounted estimated future net cash flows from proved reserves decreased 1% from year-end 2010 to 2011, primarily because of 2011 production, partially offset by a 5% increase in natural gas prices and a 22% increase in oil prices.

(b) Since the trust has defined net profits interests, the trust does not own a specific percentage of the oil and gas reserves. Because trust reserve quantities are determined using an allocation formula, any fluctuations in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the net profits interests.

(c) Before income taxes since future net cash flows are not subject to taxation at the trust level. Future net cash flows are discounted at an annual rate of 10%.

Proved reserves consist of the following:

	Underlying Properties		Net Profits Interests	
	Proved Reserves		Proved Reserves	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
(in thousands)				
Proved developed reserves	250,833	2,391	113,312	1,159
Proved undeveloped reserves	39,076	348	12,950	128
Total proved reserves	289,909	2,739	126,262	1,287

Approximately 87% of the underlying proved reserves are proved developed reserves.

The process of estimating oil and gas reserves is complex and requires significant judgment as discussed in Item 1A, Risk Factors, and is performed by XTO Energy. As a result, XTO Energy has developed internal policies and controls for estimating and recording reserves. XTO Energy's policies regarding booking reserves require proved reserves to be in compliance with the SEC definitions and guidance. XTO Energy's policies assign responsibilities for compliance in reserves bookings to its reserve engineering group and require that reserve estimates be made by qualified reserves estimators, as defined by the Society of Petroleum Engineers' standards. All qualified reserves estimators are required to receive education covering the fundamentals of SEC proved reserves assignments.

The XTO Energy reserve engineering group reviews reserve estimates with our third-party petroleum consultants, Miller and Lents, Ltd., independent petroleum engineers. Miller and Lents, Ltd. estimated oil and gas reserves attributable to the underlying properties as of December 31, 2011, 2010, 2009 and 2008. Miller and Lents' primary technical person responsible for calculating the trust's reserves has more than 30 years of experience as a reserve engineer. The estimated reserves for the underlying properties are then used by XTO Energy to calculate the estimated oil and gas reserves attributable to the net profits interests. Numerous uncertainties are inherent in estimating reserve volumes and values, and such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimates.

Reserve quantities and revenues for the net profits interests were estimated from projections of reserves and revenues attributable to the combined interests of the trust and XTO Energy in the subject properties. Since the trust has defined net profits interests, the trust does not own a specific percentage of the oil and gas reserve quantities. Accordingly, reserves allocated to the trust pertaining to its 80% net profits interests in the properties have effectively been reduced to reflect recovery of the trust's 80% portion of applicable production and development costs. Because trust reserve quantities are determined using an allocation formula, any fluctuations in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the net profits interests.

Oil and Natural Gas Production

Trust production is recognized in the period net profits income is received, which is the month following receipt by XTO Energy, and generally two months after the time of production. Oil and gas production and average sales prices attributable to the underlying properties and the net profits interests for each of the three years ended December 31 were as follows:

	2011	2010	2009
Production			
Underlying Properties			
Gas – Sales (Mcf)	**21,693,139**	24,074,923	26,641,595
Average per day (Mcf)	**59,433**	65,959	72,991
Oil – Sales (Bbls)	**248,739**	266,656	260,499
Average per day (Bbls)	**681**	731	714
Net Profits Interests			
Gas – Sales (Mcf)	**10,661,323**	12,455,292	8,326,148
Average per day (Mcf)	**29,209**	34,124	22,811
Oil – Sales (Bbls)	**130,109**	140,544	90,552
Average per day (Bbls)	**356**	385	248
Average Sales Price			
Gas (per Mcf)	**$ 4.73**	$ 4.72	$ 3.38
Oil (per Bbl)	**$90.07**	$73.77	$54.10

Oil and gas production by conveyance attributable to the underlying properties for each of the three years ended December 31 were as follows:

	Underlying Gas Production (Mcf)		
Conveyance	2011	2010	2009
Kansas	**2,007,032**	2,323,436	2,130,093
Oklahoma	**13,858,590**	15,268,280	17,344,457
Wyoming	**5,827,517**	6,483,207	7,167,045
Total	**21,693,139**	24,074,923	26,641,595

	Underlying Oil Production (Bbls)		
Conveyance	2011	2010	2009
Kansas	**20,682**	34,462	12,858
Oklahoma	**216,287**	220,149	230,838
Wyoming	**11,770**	12,045	16,803
Total	**248,739**	266,656	260,499

Pricing and Sales Information

A subsidiary of XTO Energy purchases most of XTO Energy's natural gas production based on a weighted average sales price, then sells the gas to third parties for the best available price. Oil production is generally marketed at the wellhead to third parties at the best available price. XTO Energy arranges for some of its natural gas to be processed by unaffiliated third parties and markets the natural gas liquids. Most of the natural gas attributable to the underlying properties is marketed under contracts existing at trust inception. Contracts covering production from the Ringwood area of the Major County area are generally for the life of the lease, and the contract for the majority of production from the Hugoton area was extended through 2012. If new contracts are entered with unaffiliated third parties, the proceeds from sales under those new contracts will be included in gross proceeds from the underlying properties. If new contracts are entered with XTO Energy's marketing subsidiary, it may charge XTO Energy a fee that may not exceed 2% of the sales price of the oil and natural gas received from unaffiliated parties. The sales price is net of any deductions for transportation from the wellhead to the unaffiliated parties and any gravity or quality adjustments. For further information on these arrangements see Significant Properties above.

Regulation

Natural Gas Regulation

The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation and storage rates charged, tariffs, and various other matters, by the Federal Energy Regulatory Commission. Federal price controls on wellhead sales of domestic natural gas terminated on January 1, 1993. While natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act, including enforcement rules and new annual reporting requirements for certain sellers of natural gas. It is impossible to predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, such proposals might have on the operations of the underlying properties.

Federal Regulation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances.

On December 19, 2007, the President signed into law the Energy Independence & Security Act of 2007 (PL 110-140). The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations, and establishes penalties for violations thereunder. XTO Energy has advised the trustee that it cannot predict the impact of future government regulation on any crude oil, condensate or natural gas liquids facilities, sales or transportation transactions.

Environmental Regulation

Companies that are engaged in the oil and gas industry are affected by federal, state and local laws regulating the discharge of materials into the environment. Those laws may impact operations of the underlying properties. No material expenses have been incurred on the underlying properties in complying with environmental laws and regulations. XTO Energy does not expect that future compliance will have a material adverse effect on the trust.

There is an increased focus by local, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change. Several states have adopted climate change legislation and regulations, and various other regulatory bodies have announced their intent to regulate GHG emissions or adopt climate change regulations. As these regulations are under development, XTO Energy is unable to predict the total impact of the potential regulations upon the operators of the underlying properties, and it is possible that operators of the underlying properties could face increases in operating costs in order to comply with climate change or GHG emissions legislation, which costs could reduce net proceeds payable to the trust and trust distributions.

State Regulation

The various states regulate the production and sale of oil and natural gas, including imposing requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rates of production may be regulated and the maximum daily production allowables from both oil and gas wells may be established on a market demand or conservation basis, or both.

Federal Income Taxes

For federal income tax purposes, the trust constitutes a fixed investment trust which is taxed as a grantor trust. A grantor trust is not subject to tax at the trust level. The unitholders are considered to own the trust's income and principal as though no trust were in existence. The income of the trust is deemed to have been received or accrued by each unitholder at the time such income is received or accrued by the trust and not when distributed by the trust.

Because the trust is a grantor trust for federal tax purposes, each unitholder is taxed directly on his proportionate share of income, deductions and credits of the trust consistent with each such unitholder's taxable year and method of accounting and without regard to the taxable year or method of accounting employed by the trust. The income of the trust consists primarily of a specified share of the net profits from the sale of oil and natural gas produced from the underlying properties. During 2011, the trust earned interest income on funds held for distribution and for the cash reserve maintained for the payment of contingent and future obligations of the trust.

The net profits interests constitute "economic interests" in oil and gas properties for federal tax purposes. Each unitholder is entitled to amortize the cost of the units through cost depletion over the life of the net profits interests

or, if greater, through percentage depletion equal to 15 percent of gross income. Unlike cost depletion, percentage depletion is not limited to a unitholder's depletable tax basis in the units. Rather, a unitholder is entitled to a percentage depletion deduction as long as the applicable underlying properties generate gross income. Unitholders may compute both percentage depletion and cost depletion from each property, and claim the larger amount as a deduction on their income tax returns.

If a taxpayer disposes of any "Section 1254 property" (certain oil, gas, geothermal or other mineral property), and if the adjusted basis of such property includes adjustments for deductions for depletion under Section 611 of the Internal Revenue Code, the taxpayer generally must recapture the amount deducted for depletion as ordinary income (to the extent of gain realized on the disposition of the property). This depletion recapture rule applies to any disposition of property that was placed in service by the taxpayer after December 31, 1986. Detailed rules set forth in Sections 1.1254-1 through 1.1254-6 of the U.S. Treasury Regulations govern dispositions of property after March 13, 1995. The Internal Revenue Service likely will take the position that a unitholder must recapture depletion upon the disposition of a unit.

Interest and net profits income attributable to ownership of units and any gain on the sale thereof are considered portfolio income, and not income from a "passive activity," to the extent a unitholder acquires and holds units as an investment and not in the ordinary course of a trade or business. Therefore, interest and net profits income attributable to ownership of units generally may not be offset by losses from any passive activities.

Some trust units are held by middlemen, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a customer in street name, collectively referred to herein as "middlemen"). Therefore, the trustee considers the trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. U.S. Trust, Bank of America Private Wealth Management, EIN: 56-0906609, Post Office Box 830650, Dallas, Texas. 75283-0650, telephone number 1-877-228-5083, email address trustee@hugotontrust.com, is the representative of the trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the trust as a WHFIT. Tax information is also posted by the trustee at www.hugotontrust.com. Notwithstanding the foregoing, the middlemen holding trust units on behalf of unitholders, and not the trustee of the trust, are solely responsible for complying with the information reporting requirements under the U.S. Treasury Regulations with respect to such trust units, including the issuance of IRS Forms 1099 and certain written tax statements. Unitholders whose trust units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the trust units.

Unitholders should consult their tax advisors regarding trust tax compliance matters.

State Income Taxes

All revenues from the trust are from sources within either Kansas, Oklahoma or Wyoming. Because it distributes all of its net income to unitholders, the trust has not been taxed at the trust level in Kansas or Oklahoma. While the trust has not owed tax, the Trustee is required to file a return with Oklahoma and Kansas reflecting the income and deductions of the Trust attributable to properties located in each state, along with a schedule that includes information regarding distributions to unitholders. Oklahoma and Kansas tax the income of nonresidents from real property located within those states, and the trust has been advised by counsel that those states will each tax nonresidents on income from the net profits interests located in those states. Wyoming does not have a state income tax. Kansas and Oklahoma also impose a corporate income tax that may apply to unitholders organized as corporations (subject to certain exceptions for S corporations and limited liability companies, depending on their treatment for federal tax purposes).

Each unitholder should consult his or her own tax advisor regarding state income tax requirements, if any, applicable to such person's ownership of trust units.

State Tax Withholding

Several states have enacted legislation requiring state income tax withholding from nonresident recipients of oil and gas proceeds. After consultation with its tax counsel, the trustee believes that it is not required to withhold on payments made to the unitholders. However, regulations are subject to change by the various states, which could change this conclusion. Should amounts be withheld on payments made to the trust or the unitholders, distributions to the unitholders would be reduced by the required amount, subject to the filing of a claim for refund by the trust or unitholders for such amount.

Other Regulation

The Minerals Management Service of the United States Department of the Interior amended the crude oil valuation regulations in July 2004 and the natural gas valuation regulations in June 2005 for oil and natural gas produced from federal oil and natural gas leases. The principal effect of the oil regulations pertains to which published market prices are most appropriate to value crude oil not sold in an arm's-length transaction and what transportation deductions should be allowed. The principal effect of the natural gas valuation regulations pertains to the calculation of transportation deductions and changes necessitated by judicial decisions since the regulations were last amended. Seven percent of the net acres of the underlying properties, primarily located in Wyoming, involve federal leases. Neither of these changes have had a significant effect on trust distributions.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws, including, but not limited to, regulations and laws relating to environmental protection, occupational safety, resource conservation and equal employment opportunity. XTO Energy has advised the trustee that it does not believe that compliance with these laws will have any material adverse effect upon the unitholders.

Item 3. *Legal Proceedings*

An amended petition for a class action lawsuit, *Beer, et al. v. XTO Energy Inc.*, was filed in January 2006 in the District Court of Texas County, Oklahoma by certain royalty owners of natural gas wells in Oklahoma and Kansas. The plaintiffs allege that XTO Energy has not properly accounted to the plaintiffs for the royalties to which they are entitled and seek an accounting regarding the natural gas and other products produced from their wells and the prices paid for the natural gas and other products produced, and for payment of the monies allegedly owed since June 2002, with a certain limited number of plaintiffs claiming monies owed for additional time. XTO Energy removed the case to federal district court in Oklahoma City. In April 2010, new counsel and representative parties, Fankhouser and Goddard, filed a motion to intervene and prosecute the *Beer* class, now styled *Fankhouser v. XTO Energy Inc*. This motion was granted on July 13, 2010. The new plaintiffs and counsel filed an amended complaint asserting new causes of action for breach of fiduciary duties and unjust enrichment. On December 16, 2010, the court certified the class. Cross motions for summary judgment have been filed by the parties, and the case is set for trial in April 2012. XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to this lawsuit and intends to vigorously defend its position.

In September 2008, a class action lawsuit was filed against XTO Energy styled *Wallace B. Roderick Revocable Living Trust, et al. v. XTO Energy Inc.* in the District Court of Kearny County, Kansas. XTO Energy removed the case to federal court in Wichita, Kansas. The plaintiffs allege that XTO Energy has improperly taken post-production costs from royalties paid to the plaintiffs from wells located in Kansas, Oklahoma and Colorado. The plaintiffs have filed a motion to certify the class, including only Kansas and Oklahoma wells not part of the Fankhouser matter. After filing the motion to certify, but prior to the class certification hearing, the plaintiff filed a motion to sever the Oklahoma portion of the case so it could be transferred and consolidated with a newly filed class action in Oklahoma styled *Chieftain Royalty Company v. XTO Energy Inc*. This motion was granted. The Roderick case now comprises only Kansas wells not previously included in the Fankhouser matter. XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to this lawsuit and intends to vigorously defend its position.

In December 2010, a class action lawsuit was filed against XTO Energy styled *Chieftain Royalty Company v. XTO Energy Inc.* in Coal County District Court, Oklahoma. XTO Energy removed the case to federal court in the Eastern

District of Oklahoma. The plaintiffs allege that XTO Energy wrongfully deducted fees from royalty payments on Oklahoma wells, failed to make diligent efforts to secure the best terms available for the sale of gas and its constituents, and demand an accounting to determine whether they have been fully and fairly paid gas royalty interests. The case expressly excludes those claims and wells being prosecuted in the Fankhouser case. The severed Roderick case claims related to the Oklahoma portion of the case were consolidated into *Chieftain*. XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to this lawsuit and intends to vigorously defend its position.

If XTO Energy ultimately makes any settlement payments or receives a judgment against it in any of the cases named above, the trust will bear its 80% share of such settlement or judgment related to production from the underlying properties. Additionally, if the judgment or settlement increases the amount of future payments to royalty owners, the trust would bear its proportionate share of the increased payments through reduced net proceeds. XTO Energy has informed the trustee that, although the amount of any reduction in net proceeds is not presently determinable, in its management's opinion, the amount is not currently expected to be material to the trust's financial position or liquidity though it could be material to the trust's annual distributable income. Additionally, it could result in costs exceeding revenues on the properties underlying the Oklahoma and Kansas net profit interests for one or more monthly distributions, depending on the size of the judgment or settlement, if any, and the net proceeds being paid at that time.

Certain of the underlying properties are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. XTO Energy has advised the trustee that it does not believe that the ultimate resolution of these claims will have a material effect on trust annual distributable income, financial position or liquidity.

Item 4. ***Mine Safety Disclosures***

Not Applicable.

Results of Operations

Years Ended December 31, 2011, 2010 and 2009

Net profits income for 2011 was $56,565,368, as compared with $62,883,206 for 2010 and $30,180,880 for 2009. The 10% decrease in net profits income from 2010 to 2011 is primarily the result of decreased oil and gas production ($10.3 million), partially offset by higher oil prices ($3.5 million). The 108% increase in net profits income from 2009 to 2010 is primarily the result of higher oil and gas prices ($32.6 million) and decreased development costs ($11.0 million), partially offset by decreased gas production ($9.7 million). Approximately 81% in 2011, 85% in 2010 and 84% in 2009 of net profits income was derived from natural gas sales.

Trust administration expense was $801,563 in 2011 as compared to $856,314 in 2010 and $875,105 in 2009. Interest income was $1,155 in 2011, $1,108 in 2010 and $465 in 2009. Changes in interest income are attributable to fluctuations in net profits income and interest rates. Distributable income was $55,764,960 or $1.394124 per unit in 2011, $62,028,000 or $1.550700 per unit in 2010 and $29,306,240 or $0.732656 per unit in 2009.

Net profits income is recorded when received by the trust, which is the month following receipt by XTO Energy, and generally two months after oil and gas production. Net profits income is generally affected by three major factors:

- oil and gas sales volumes,
- oil and gas sales prices, and
- costs deducted in the calculation of net profits income.

Volumes

From 2010 to 2011, underlying gas sales volumes decreased 10% primarily due to natural production decline. Underlying oil sales volumes decreased 7% primarily because of natural production decline and the timing of cash receipts. From 2009 to 2010, underlying gas sales volumes decreased 10% primarily due to natural production decline and the timing of cash receipts, partially offset by increased production from new wells and workovers. Underlying oil sales volumes increased 2% from 2009 to 2010 primarily because of increased production from new wells and workovers, partially offset by natural production decline and the timing of cash receipts.

The estimated rate of natural production decline on the underlying oil and gas properties is approximately 6% to 8% a year.

Prices

Gas. The 2011 average gas price was $4.73 per Mcf, relatively flat from the 2010 average gas price of $4.72 per Mcf, which was 40% higher than the 2009 average gas price of $3.38 per Mcf. Natural gas prices are affected by the level of North American production, weather, crude oil and natural gas liquids prices, the U.S. economy, storage levels and import levels of liquefied natural gas. Natural gas prices are expected to remain volatile. The average NYMEX price for November 2011 through January 2012 was $3.20 per MMBtu. At February 10, 2012, the average NYMEX gas price for the following 12 months was $3.08 per MMBtu.

Oil. The average oil price for 2011 was $90.07 per Bbl, 22% higher than the average oil price for 2010 of $73.77 per Bbl, which was 36% higher than the average oil price for 2009 of $54.10 per Bbl. Oil prices are expected to remain volatile. The average NYMEX price for November 2011 through January 2012 was $98.53 per Bbl. At February 10, 2012, the average NYMEX oil price for the following 12 months was $100.99 per Bbl.

Costs

The calculation of net profits income includes deductions for production expense, development costs and overhead since the related underlying properties are working interests. If monthly costs exceed revenues for any state, these excess costs must be recovered, with accrued interest, from future net proceeds of that state and cannot reduce net profits income from another state. See “Excess costs” below.

Taxes, transportation and other. Taxes, transportation and other generally fluctuates with changes in total revenues. Taxes, transportation and other decreased 11% from 2010 to 2011 primarily because of decreased property taxes related to the timing of expenditures and decreased gas production taxes and other deductions related to lower gas revenues, partially offset by increased oil production taxes related to higher oil revenues. Taxes, transportation and other increased 10% from 2009 to 2010 primarily because of increased production taxes related to higher revenues, partially offset by decreased property taxes.

Production. Production expense remained relatively flat from 2010 to 2011 primarily because increased labor, field, fuel and compressor rental costs were offset by mechanical and marketing rebates received in 2011, decreased insurance, plugging and abandonment and repairs and maintenance costs. Production expense remained relatively flat from 2009 to 2010 as increased repairs and maintenance and fuel costs were offset by decreased compressor rentals and outside operated costs.

Development. Development costs deducted were $8.8 million in 2011, $7.3 million in 2010 and $21.0 million in 2009. In 2011, actual development costs were $5.6 million. At December 31, 2011, cumulative budgeted costs exceeded cumulative actual costs by approximately $2.4 million. The monthly development cost deduction was $4.0 million from the January 2009 distribution through the March 2009 distribution. As a result of decreased development activity and revisions to the 2009 development budget, the development cost deduction was decreased to $2.0 million beginning with the April 2009 distribution, to $1.0 million beginning with the June 2009 distribution and to $500,000 beginning with the September 2009 distribution and was maintained at that level through the July 2010 distribution. As a result of increased development activity, the development cost deduction was increased to $600,000 beginning with the August 2010 distribution and to $850,000 beginning with the October 2010 distribution and was maintained at that level through the August 2011 distribution. Due to lower than anticipated actual costs as a result of reduced activity, the development cost deduction was decreased to $500,000 beginning with the September 2011 distribution and was maintained at that level for the remainder of 2011. For further information on 2012 budgeted development costs, see Properties, under Item 2. The monthly deduction is based on the current level of development expenditures, budgeted future development costs and the cumulative actual costs under (over) previous deductions. XTO Energy has advised the trustee that this monthly deduction will continue to be evaluated and revised as necessary.

Overhead. Overhead is charged by XTO Energy for administrative expenses incurred to support operations of the underlying properties. Overhead fluctuates based on changes in the active well count and drilling activity on the underlying properties, as well as an annual cost level adjustment.

Excess costs. Costs exceeded revenues by $513,475 ($410,780 net to the trust) on properties underlying the Kansas net profits interests in October and November 2009. Lower gas prices caused costs to exceed revenues on properties underlying the Kansas net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the partial recovery of excess costs of $410,957 ($328,766 net to the trust), plus accrued interest of $1,958 ($1,566 net to the trust) in December 2009 and the full recovery of excess costs of $102,518 ($82,014 net to the trust), plus accrued interest of $282 ($226 net to the trust) in January 2010.

There were no excess costs as of December 31, 2011.

Fourth Quarter 2011 and 2010

During fourth quarter 2011 the trust received net profits income totaling $13,206,026 compared with fourth quarter 2010 net profits income of $12,314,499. This 7% increase in net profits income was primarily due to higher oil and gas prices ($3.0 million) and decreased development costs ($0.8 million), partially offset by decreased oil and gas production ($3.1 million).

Administration expense was $117,530 and interest income was $344, resulting in fourth quarter 2011 distributable income of $13,088,840 or $0.327221 per unit. Distributable income for fourth quarter 2010 was $12,202,600 or $0.305065 per unit.

Distributions to unitholders for the quarter ended December 31, 2011 were:

Record Date	Payment Date	Per Unit
October 31, 2011	November 15, 2011	$0.126934
November 30, 2011	December 14, 2011	0.110344
December 30, 2011	January 17, 2012	0.089943
		$0.327221

Volumes

Fourth quarter underlying gas sales volumes decreased 12% and underlying oil sales volumes decreased 9% from 2010 to 2011. Gas sales volumes decreased primarily because of natural production decline and scheduled maintenance on a gathering and processing system in the Hugoton area in October 2011. Oil sales volumes decreased primarily because of natural production decline.

Prices

The average fourth quarter 2011 gas price was $4.70 per Mcf, or 12% higher than the fourth quarter 2010 average price of $4.18 per Mcf. The average fourth quarter 2011 oil price was $83.12 per Bbl, or 12% higher than the fourth quarter 2010 average price of $74.46 per Bbl. For further information about product prices, see "Years Ended December 31, 2011, 2010 and 2009 – Prices" above.

Costs

Production. Fourth quarter production expense decreased 2% from 2010 to 2011 primarily because of decreased insurance, location, repairs and maintenance and water disposal costs, partially offset by increased labor and fuel costs.

Development. Development costs, which were deducted based on budgeted development costs, decreased 41% from fourth quarter 2010 to 2011 primarily because of lower than anticipated actual costs as a result of reduced activity.

Overhead. Overhead decreased 3% from fourth quarter 2010 to 2011 primarily because of a lower active well count.

Liquidity and Capital Resources

The trust's only cash requirement is the monthly distribution of its income to unitholders, which is funded by the monthly receipt of net profits income after payment of trust administration expenses. The trust is not liable for any production costs or liabilities attributable to the net profits interests. If at any time the trust receives net profits income in excess of the amount due, the trust is not obligated to return such overpayment, but future net profits income payable to the trust will be reduced by the overpayment, plus interest at the prime rate. The trust may borrow funds required to pay trust liabilities if fully repaid prior to further distributions to unitholders.

The trust does not have any transactions, arrangements or other relationships with unconsolidated entities or persons that could materially affect the trust's liquidity or the availability of capital resources.

Greenhouse Gas Emissions and Climate Change Regulation

There is an increased focus by local, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change. Several states have adopted climate change legislation and regulations, and various other regulatory bodies have announced their intent to regulate GHG emissions or adopt climate change regulations.

As these regulations are under development, XTO Energy is unable to predict the total impact of the potential regulations upon the operators of the underlying properties, and it is possible that the operators of the underlying properties could face increases in operating costs in order to comply with climate change or GHG emissions legislation, which costs could reduce net proceeds payable to the trust and trust distributions.

Off-Balance Sheet Arrangements

The trust has no off-balance sheet financing arrangements. The trust has not guaranteed the debt of any other party, nor does the trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations.

Contractual Obligations

As shown below, the trust had no obligations and commitments to make future contractual payments as of December 31, 2011, other than the December distribution payable to unitholders in January 2012, as reflected in the statement of assets, liabilities and trust corpus.

	Payments due by Period				
	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Distribution payable to unitholders	$3,597,720	$3,597,720	$—	$—	$—

Related Party Transactions

The underlying properties from which the net profits interests were carved are currently owned by XTO Energy, which operates approximately 95% of the underlying properties. In computing net proceeds, XTO Energy deducts a monthly overhead charge for reimbursement of administrative expenses on the underlying properties it operates. As of December 31, 2011, the monthly overhead charge, based on the number of operated wells, was approximately $907,000 ($725,600 net to the trust) and is subject to annual adjustment based on an oil and gas industry index.

XTO Energy sells a significant portion of natural gas production from the underlying properties to certain of XTO Energy's wholly owned subsidiaries under contracts in existence when the trust was created, generally at amounts approximating monthly published market prices. For further information regarding natural gas sales from the underlying properties to affiliates of XTO Energy, see Significant Properties, under Item 2, Properties and Note 8 to Financial Statements under Item 8, Financial Statements and Supplementary Data. Total gas sales from the underlying properties to XTO Energy's wholly owned subsidiaries were $35.6 million for 2011, or 35% of total gas sales, $48.5 million for 2010, or 43% of total gas sales and $42.2 million for 2009, or 47% of total gas sales.

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation.

Critical Accounting Policies

The financial statements of the trust are significantly affected by its basis of accounting and estimates related to its oil and gas properties and proved reserves, as summarized below.

Basis of Accounting

The trust's financial statements are prepared on a modified cash basis, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles. This method of accounting is consistent with reporting of taxable income to trust unitholders. The most significant differences between the trust's financial statements and those prepared in accordance with U.S. generally accepted accounting principles are:

- Net profits income is recognized in the month received rather than accrued in the month of production.

- Expenses are recognized when paid rather than when incurred.
- Cash reserves may be established by the trustee for certain contingencies that would not be recorded under U.S. generally accepted accounting principles.

This comprehensive basis of accounting other than U.S. generally accepted accounting principles corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission, as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts. For further information regarding the trust's basis of accounting, see Note 2 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

All amounts included in the trust's financial statements are based on cash amounts received or disbursed, or on the carrying value of the net profits interests, which was derived from the historical cost of the interests at the date of their transfer from XTO Energy, less accumulated amortization to date. Accordingly, there are no fair value estimates included in the financial statements based on either exchange or nonexchange trade values.

Oil and Gas Reserves

The proved oil and gas reserves for the underlying properties are estimated by independent petroleum engineers. The estimated reserves for the underlying properties are then used by XTO Energy to calculate the estimated oil and gas reserves attributable to the net profits interests. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices, may justify revision of such estimates. Because proved reserves are required to be estimated using 12-month average prices, based on the first-day-of-the-month price for each month in the period, estimated reserve quantities can be significantly impacted by changes in product prices. Accordingly, oil and gas quantities ultimately recovered and the timing of production may be substantially different from original estimates.

The standardized measure of discounted future net cash flows and changes in such cash flows, as reported in Note 10 to Financial Statements under Item 8, Financial Statements and Supplementary Data, is prepared using assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission. Such assumptions include using 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period for 2011, 2010 and 2009, and year end costs for estimated future development and production expenditures. Prior to 2009, standardized measure was calculated using year end oil and gas prices and costs. Discounted future net cash flows are calculated using a 10% rate. Changes in any of these assumptions, including consideration of other factors, could have a significant impact on the standardized measure. Accordingly, the standardized measure does not represent XTO Energy's or the trustee's estimated current market value of proved reserves.

Forward-Looking Statements

Certain information included in this annual report and other materials filed, or to be filed, by the trust with the Securities and Exchange Commission (as well as information included in oral statements or other written statements made or to be made by XTO Energy or the trustee) contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended, relating to the trust, operations of the underlying properties and the oil and gas industry. Such forward-looking statements may concern, among other things, reserve-to-production ratios, future production, development activities, future development plans by area, increased density drilling, maintenance projects, development, production and other costs, oil and gas prices, pricing differentials, proved reserves, future net cash flows, production levels, litigation, regulatory matters and competition. Such forward-looking statements are based on XTO Energy's current plans, expectations, assumptions, projections and estimates and are identified by words such as "expects," "intends," "plans," "projects," "anticipates," "predicts," "believes," "goals," "estimates," "should," "could", and similar words that convey the uncertainty of future events. These statements are not guarantees of future performance and involve certain

risks, uncertainties and assumptions that are difficult to predict. Therefore, actual results may differ materially from expectations, estimates or assumptions expressed in, implied in, or forecasted in such forward-looking statements. Some of the risk factors that could cause actual results to differ materially are explained in Item 1A, Risk Factors.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

The only assets of and sources of income to the trust are the net profits interests, which generally entitle the trust to receive a share of the net profits from oil and gas production from the underlying properties. Consequently, the trust is exposed to market risk from fluctuations in oil and gas prices. The trust is a passive entity and, other than the trust's ability to periodically borrow money as necessary to pay expenses, liabilities and obligations of the trust that cannot be paid out of cash held by the trust, the trust is prohibited from engaging in borrowing transactions. The amount of any such borrowings is unlikely to be material to the trust. In addition, the trustee is prohibited by the trust indenture from engaging in any business activity or causing the trust to enter into any investments other than investing cash on hand in specific short-term cash investments. Therefore, the trust cannot hold any derivative financial instruments. As a result of the limited nature of its borrowing and investing activities, the trust is not subject to any material interest rate market risk. Additionally, any gains or losses from any hedging activities conducted by XTO Energy are specifically excluded from the calculation of net proceeds due the trust under the forms of the conveyances. The trust does not engage in transactions in foreign currencies which could expose the trust to any foreign currency related market risk.

Item 8. ***Financial Statements and Supplementary Data***

	Page
Statements of Assets, Liabilities and Trust Corpus	28
Statements of Distributable Income	29
Statements of Changes in Trust Corpus	30
Notes to Financial Statements	31
Reports of Independent Registered Public Accounting Firm	41

All financial statement schedules are omitted as they are inapplicable or the required information has been included in the consolidated financial statements or notes thereto.

HUGOTON ROYALTY TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31	
	2011	**2010**
Assets		
Cash and short-term investments	**$ 3,597,720**	$ 4,229,120
Net profits interests in oil and gas properties – net (Notes 1 and 2)	**115,367,996**	124,993,766
	$118,965,716	$129,222,886
Liabilities and Trust Corpus		
Distribution payable to unitholders	**$ 3,597,720**	$ 4,229,120
Trust corpus (40,000,000 units of beneficial interest authorized and outstanding)	**115,367,996**	124,993,766
	$118,965,716	$129,222,886

See accompanying notes to financial statements.

HUGOTON ROYALTY TRUST

STATEMENTS OF DISTRIBUTABLE INCOME

	Year Ended December 31		
	2011	**2010**	**2009**
Net profits income	**$56,565,368**	$62,883,206	$30,180,880
Interest income	**1,155**	1,108	465
Total income	**56,566,523**	62,884,314	30,181,345
Administration expense	**801,563**	856,314	875,105
Distributable income	**$55,764,960**	$62,028,000	$29,306,240
Distributable income per unit (40,000,000 units)	**$ 1.394124**	$ 1.550700	$ 0.732656

See accompanying notes to financial statements.

HUGOTON ROYALTY TRUST

STATEMENTS OF CHANGES IN TRUST CORPUS

	Year Ended December 31		
	2011	**2010**	**2009**
Trust corpus, beginning of year	**$124,993,766**	$139,877,580	$146,722,015
Amortization of net profits interests	**(9,625,770)**	(14,883,814)	(6,844,435)
Distributable income	**55,764,960**	62,028,000	29,306,240
Distributions declared	**(55,764,960)**	(62,028,000)	(29,306,240)
Trust corpus, end of year	**$115,367,996**	$124,993,766	$139,877,580

See accompanying notes to financial statements.

HUGOTON ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS

1. Trust Organization and Provisions

Hugoton Royalty Trust was created on December 1, 1998 by XTO Energy Inc. (formerly known as "Cross Timbers Oil Company"). Effective on that date, XTO Energy conveyed 80% net profits interests in certain predominantly gas-producing working interest properties in Kansas, Oklahoma and Wyoming to the trust under separate conveyances for each of the three states. In exchange for the conveyances of the net profits interests to the trust, XTO Energy received 40 million units of beneficial interest in the trust. The trust's initial public offering was in April 1999. The majority of the underlying working interest properties are currently owned and operated by XTO Energy (Note 8).

Bank of America, N.A. is the trustee for the trust. In 2007 the Bank of America private wealth management group officially became known as "U.S. Trust, Bank of America Private Wealth Management." The legal entity that serves as the trustee of the trust did not change, and references in this Annual Report to U.S. Trust, Bank of America Private Wealth Management shall describe the legal entity Bank of America, N.A. The trust indenture provides, among other provisions, that:

- the trust cannot engage in any business activity or acquire any assets other than the net profits interests and specific short-term cash investments;
- the trust may dispose of all or part of the net profits interests if approved by 80% of the unitholders, or upon trust termination. Otherwise, the trust may sell up to 1% of the value of the net profits interests in any calendar year, pursuant to notice from XTO Energy of its desire to sell the related underlying properties. Any sale must be for cash with the proceeds promptly distributed to the unitholders;
- the trustee may establish a cash reserve for payment of any liability that is contingent or not currently payable;
- the trustee may borrow funds to pay trust liabilities if repaid in full prior to further distributions to unitholders;
- the trustee will make monthly cash distributions to unitholders (Note 3); and
- the trust will terminate upon the first occurrence of:
    - disposition of all net profits interests pursuant to terms of the trust indenture,
    - gross proceeds from the underlying properties falling below $1 million per year for two successive years, or
    - a vote of 80% of the unitholders to terminate the trust in accordance with provisions of the trust indenture.

2. Basis of Accounting

The financial statements of the trust are prepared on the following basis and are not intended to present financial position and results of operations in conformity with U.S. generally accepted accounting principles:

- Net profits income is recorded in the month received by the trustee (Note 3).
- Trust expenses are recorded based on liabilities paid and cash reserves established by the trustee for liabilities and contingencies.
- Distributions to unitholders are recorded when declared by the trustee (Note 3).

The most significant differences between the trust's financial statements and those prepared in accordance with U.S. generally accepted accounting principles are:

- Net profits income is recognized in the month received rather than accrued in the month of production.
- Expenses are recognized when paid rather than when incurred.
- Cash reserves may be established by the trustee for contingencies that would not be recorded under U.S. generally accepted accounting principles.

This comprehensive basis of accounting corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission, as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with U.S. generally accepted accounting principles, directing such entities to accrue or defer revenues and expenses in a period other than when such revenues were received or expenses were paid. Because the trust's financial statements are prepared on the modified cash basis, as described above, most accounting pronouncements are not applicable to the trust's financial statements.

The initial carrying value of the net profits interests of $247,066,951 was XTO Energy's historical net book value of the interests on December 1, 1998, the date of the transfer to the trust. Amortization of the net profits interests is calculated on a unit-of-production basis and charged directly to trust corpus. Accumulated amortization was $131,698,955 as of December 31, 2011 and $122,073,185 as of December 31, 2010.

3. Distributions to Unitholders

The trustee determines the amount to be distributed to unitholders each month by totaling net profits income, interest income and other cash receipts, and subtracting liabilities paid and adjustments in cash reserves established by the trustee. The resulting amount is distributed to unitholders of record within ten business days after the monthly record date, which is the last business day of the month.

Net profits income received by the trustee consists of net proceeds received in the prior month by XTO Energy from the underlying properties, multiplied by 80%. Net proceeds are the gross proceeds received from the sale of production, less costs. Costs generally include applicable taxes, transportation, legal and marketing charges, production expense, development and drilling costs, and overhead (Note 8).

XTO Energy, as owner of the underlying properties, computes net profits income separately for each of the three conveyances (one for each of the states of Kansas, Oklahoma and Wyoming). If costs exceed revenues for any conveyance, such excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net profits income from the other conveyances (Note 4).

4. Excess Costs

Costs exceeded revenues by $513,475 ($410,780 net to the trust) on properties underlying the Kansas net profits interests in October and November 2009. Lower gas prices caused costs to exceed revenues on properties underlying the Kansas net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the partial recovery of excess costs of $410,957 ($328,766 net to the trust), plus accrued interest of $1,958 ($1,566 net to the trust) in December 2009 and the full recovery of excess costs of $102,518 ($82,014 net to the trust), plus accrued interest of $282 ($226 net to the trust) in January 2010.

There were no excess costs as of December 31, 2011.

5. Development Costs

The following summarizes actual development costs, budgeted development costs deducted in the calculation of net profits income, and the cumulative actual costs compared to the amount deducted:

	Year Ended December 31		
	2011	**2010**	**2009**
Cumulative actual costs (over) under the amount deducted – beginning of period	**$ (809,696)**	$ 909,477	$ (7,314,084)
Actual costs	**(5,593,384)**	(8,969,173)	(12,776,439)
Budgeted costs deducted	**8,800,000**	7,250,000	21,000,000
Cumulative actual costs under (over) the amount deducted – end of period	**$ 2,396,920**	$ (809,696)	$ 909,477

The monthly development cost deduction was $4.0 million from the January 2009 distribution through the March 2009 distribution. As a result of decreased development activity and revisions to the 2009 development budget, the development cost deduction was decreased to $2.0 million beginning with the April 2009 distribution, to $1.0 million beginning with the June 2009 distribution and to $500,000 beginning with the September 2009 distribution and was maintained at that level through the July 2010 distribution. As a result of increased development activity, the development cost deduction was increased to $600,000 beginning with the August 2010 distribution and to $850,000 beginning with the October 2010 distribution and was maintained at that level through the August 2011 distribution. Due to lower than anticipated actual costs as a result of reduced activity, the development cost deduction was decreased to $500,000 beginning with the September 2011 distribution and was maintained at that level for the remainder of 2011. For further information on 2012 budgeted development costs, see Properties, under Item 2. The monthly deduction is based on the current level of development expenditures, budgeted future development costs and the cumulative actual costs under (over) previous deductions. XTO Energy has advised the trustee that this monthly deduction will continue to be evaluated and revised as necessary.

6. Federal Income Taxes

For federal income tax purposes, the trust constitutes a fixed investment trust which is taxed as a grantor trust. A grantor trust is not subject to tax at the trust level. The unitholders are considered to own the trust's income and principal as though no trust were in existence. The income of the trust is deemed to have been received or accrued by each unitholder at the time such income is received or accrued by the trust and not when distributed by the trust.

Because the trust is a grantor trust for federal tax purposes, each unitholder is taxed directly on his proportionate share of income, deductions and credits of the trust consistent with each such unitholder's taxable year and method of accounting and without regard to the taxable year or method of accounting employed by the trust. The income of the trust consists primarily of a specified share of the net profits from the sale of oil and natural gas produced from the underlying properties. During 2011, the trust earned interest income on funds held for distribution and for the cash reserve maintained for the payment of contingent and future obligations of the trust.

The net profits interests constitute "economic interests" in oil and gas properties for federal tax purposes. Each unitholder is entitled to amortize the cost of the units through cost depletion over the life of the net profits interests or, if greater, through percentage depletion equal to 15 percent of gross income. Unlike cost depletion, percentage depletion is not limited to a unitholder's depletable tax basis in the units. Rather, a unitholder is entitled to a percentage depletion deduction as long as the applicable underlying properties generate gross income. Unitholders may compute both percentage depletion and cost depletion from each property, and claim the larger amount as a deduction on their income tax returns.

If a taxpayer disposes of any "Section 1254 property" (certain oil, gas, geothermal or other mineral property), and if the adjusted basis of such property includes adjustments for deductions for depletion under Section 611 of the Internal Revenue Code, the taxpayer generally must recapture the amount deducted for depletion as ordinary income (to the extent of gain realized on the disposition of the property). This depletion recapture rule applies to any disposition of property that was placed in service by the taxpayer after December 31, 1986. Detailed rules set forth in Sections 1.1254-1 through 1.1254-6 of the U.S. Treasury Regulations govern dispositions of property after March 13, 1995. The Internal Revenue Service likely will take the position that a unitholder must recapture depletion upon the disposition of a unit.

Interest and net profits income attributable to ownership of units and any gain on the sale thereof are considered portfolio income, and not income from a "passive activity," to the extent a unitholder acquires and holds units as an investment and not in the ordinary course of a trade or business. Therefore, interest and net profits income attributable to ownership of units generally may not be offset by losses from any passive activities.

Some trust units are held by middlemen, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a customer in street name, collectively referred to herein as "middlemen"). Therefore, the trustee considers the trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. U.S. Trust, Bank of America Private Wealth Management, EIN: 56-0906609, Post Office Box 830650, Dallas, Texas. 75283-0650, telephone number 1-877-228-5083, email address trustee@hugotontrust.com, is the representative of the trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the trust as a WHFIT. Tax information is also posted by the trustee at www.hugotontrust.com. Notwithstanding the foregoing, the middlemen holding trust units on behalf of unitholders, and not the trustee of the trust, are solely responsible for complying with the information reporting requirements under the U.S. Treasury Regulations with respect to such trust units, including the issuance of IRS Forms 1099 and certain written tax statements. Unitholders whose trust units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the trust units.

Unitholders should consult their tax advisors regarding trust tax compliance matters.

7. State Income Taxes

All revenues from the trust are from sources within either Kansas, Oklahoma or Wyoming. Because it distributes all of its net income to unitholders, the trust has not been taxed at the trust level in Kansas or Oklahoma. While the trust has not owed tax, the Trustee is required to file a return with Oklahoma and Kansas reflecting the income and deductions of the Trust attributable to properties located in each state, along with a schedule that includes information regarding distributions to unitholders. Oklahoma and Kansas tax the income of nonresidents from real property located within those states, and the trust has been advised by counsel that those states will each tax nonresidents on income from the net profits interests located in those states. Wyoming does not have a state income tax. Kansas and Oklahoma also impose a corporate income tax that may apply to unitholders organized as corporations (subject to certain exceptions for S corporations and limited liability companies, depending on their treatment for federal tax purposes).

Each unitholder should consult his or her own tax advisor regarding state income tax requirements, if any, applicable to such person's ownership of trust units.

8. XTO Energy Inc.

XTO Energy operates approximately 95% of the underlying properties. In computing net proceeds, XTO Energy deducts an overhead charge for reimbursement of administrative expenses on the underlying properties it operates. As

of December 31, 2011, the overhead charge was approximately $907,000 ($725,600 net to the trust) per month and is subject to annual adjustment based on an oil and gas industry index as defined in the trust agreement.

XTO Energy sells a significant portion of natural gas production from the underlying properties to certain of XTO Energy's wholly owned subsidiaries under contracts in existence when the trust was created, generally at amounts approximating monthly published market prices. Most of the production from the Hugoton area is sold under a contract to Timberland Gathering & Processing Company, Inc. ("TGPC") based on the index price. Much of the gas production in Major County, Oklahoma is sold to Ringwood Gathering Company ("RGC"), which retains approximately $0.31 per Mcf as a compression and gathering fee. TGPC and RGC sell gas to Cross Timbers Energy Services, Inc. ("CTES"), which markets gas to third parties. XTO Energy sells directly to CTES most gas production not sold directly to TGPC or RGC.

Total gas sales from the underlying properties to XTO Energy's wholly owned subsidiaries were $35.6 million for 2011, or 35% of total gas sales, $48.5 million for 2010, or 43% of total gas sales and, $42.2 million for 2009, or 47% of total gas sales.

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation.

9. Contingencies

Litigation

An amended petition for a class action lawsuit, *Beer, et al. v. XTO Energy Inc.*, was filed in January 2006 in the District Court of Texas County, Oklahoma by certain royalty owners of natural gas wells in Oklahoma and Kansas. The plaintiffs allege that XTO Energy has not properly accounted to the plaintiffs for the royalties to which they are entitled and seek an accounting regarding the natural gas and other products produced from their wells and the prices paid for the natural gas and other products produced, and for payment of the monies allegedly owed since June 2002, with a certain limited number of plaintiffs claiming monies owed for additional time. XTO Energy removed the case to federal district court in Oklahoma City. In April 2010, new counsel and representative parties, Fankhouser and Goddard, filed a motion to intervene and prosecute the *Beer* class, now styled *Fankhouser v. XTO Energy Inc*. This motion was granted on July 13, 2010. The new plaintiffs and counsel filed an amended complaint asserting new causes of action for breach of fiduciary duties and unjust enrichment. On December 16, 2010, the court certified the class. Cross motions for summary judgment have been filed by the parties, and the case is set for trial in April 2012. XTO Energy has informed the trustee that XTO Energy believes that it has strong defenses to this lawsuit and intends to vigorously defend its position.

In September 2008, a class action lawsuit was filed against XTO Energy styled *Wallace B. Roderick Revocable Living Trust, et al. v. XTO Energy Inc.* in the District Court of Kearny County, Kansas. XTO Energy removed the case to federal court in Wichita, Kansas. The plaintiffs allege that XTO Energy has improperly taken post-production costs from royalties paid to the plaintiffs from wells located in Kansas, Oklahoma and Colorado. The plaintiffs have filed a motion to certify the class, including only Kansas and Oklahoma wells not part of the Fankhouser matter. After filing the motion to certify, but prior to the class certification hearing, the plaintiff filed a motion to sever the Oklahoma portion of the case so it could be transferred and consolidated with a newly filed class action in Oklahoma styled *Chieftain Royalty Company v. XTO Energy Inc.* This motion was granted. The Roderick case now comprises only Kansas wells not previously included in the Fankhouser matter. XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to this lawsuit and intends to vigorously defend its position.

In December 2010, a class action lawsuit was filed against XTO Energy styled *Chieftain Royalty Company v. XTO Energy Inc.* in Coal County District Court, Oklahoma. XTO Energy removed the case to federal court in the Eastern

District of Oklahoma. The plaintiffs allege that XTO Energy wrongfully deducted fees from royalty payments on Oklahoma wells, failed to make diligent efforts to secure the best terms available for the sale of gas and its constituents, and demand an accounting to determine whether they have been fully and fairly paid gas royalty interests. The case expressly excludes those claims and wells being prosecuted in the Fankhouser case. The severed Roderick case claims related to the Oklahoma portion of the case were consolidated into *Chieftain*. XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to this lawsuit and intends to vigorously defend its position.

If XTO Energy ultimately makes any settlement payments or receives a judgment against it in any of the cases named above, the trust will bear its 80% share of such settlement or judgment related to production from the underlying properties. Additionally, if the judgment or settlement increases the amount of future payments to royalty owners, the trust would bear its proportionate share of the increased payments through reduced net proceeds. XTO Energy has informed the trustee that, although the amount of any reduction in net proceeds is not presently determinable, in its management's opinion, the amount is not currently expected to be material to the trust's financial position or liquidity though it could be material to the trust's annual distributable income. Additionally, it could result in costs exceeding revenues on the properties underlying the Oklahoma and Kansas net profit interests for one or more monthly distributions, depending on the size of the judgment or settlement, if any, and the net proceeds being paid at that time.

Certain of the underlying properties are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. XTO Energy has advised the trustee that it does not believe that the ultimate resolution of these claims will have a material effect on trust annual distributable income, financial position or liquidity.

Other

Several states have enacted legislation requiring state income tax withholding from nonresident recipients of oil and gas proceeds. After consultation with its tax counsel, the trustee believes that it is not required to withhold on payments made to the unitholders. However, regulations are subject to change by the various states, which could change this conclusion. Should amounts be withheld on payments made to the trust or the unitholders, distributions to the unitholders would be reduced by the required amount, subject to the filing of a claim for refund by the trust or unitholders for such amount.

10. Supplemental Oil and Gas Reserve Information (Unaudited)

Oil and Natural Gas Reserves

Proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared with the cost of a new well. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period for 2011, 2010 and 2009, and year end costs for estimated future development and production expenditures to produce the proved reserves. Prior to 2009, standardized measure was calculated using year end oil and gas prices and costs. Future net cash flows are discounted at an annual rate of 10%. No provision is included for federal income taxes since future net cash flows are not subject to taxation at the trust level.

The standardized measure does not represent management's estimate of our future cash flows or the value of proved oil and gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as affected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

Estimated costs to plug and abandon wells on the underlying working interest properties at the end of their productive lives have not been deducted from cash flows since this is not a legal obligation of the trust. These costs are the legal obligation of XTO Energy as the owner of the underlying working interests and will only be deducted from net proceeds payable to the trust if net proceeds from the related conveyance exceed such costs when paid, subject to excess cost carryforward provisions (Notes 3 and 4).

The average realized gas prices used to determine the standardized measure were $4.67 per Mcf in 2011, $4.45 per Mcf in 2010, and $3.28 per Mcf in 2009 and a year end realized gas price of $4.47 per Mcf in 2008. Oil prices used to determine the standardized measure were based on average realized oil prices of $92.92 per Bbl in 2011, $75.91 per Bbl in 2010, and $57.17 per Bbl in 2009 and a year end realized oil price of $42.13 per Bbl in 2008. In 2011, 2010 and 2009, we used average oil and gas prices, based on the first-day-of-the-month price for each month in the period. For periods prior to 2009, we used year end oil and gas prices.

Proved Reserves

	Underlying Properties		Net Profits Interests	
(in thousands)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
Balance, December 31, 2008	366,305	3,309	178,483	1,682
Extensions, additions and discoveries	5,447	354	2,369	154
Revisions of prior estimates	(21,865)	(398)	(55,473)	(621)
Production – sales volumes	(26,642)	(260)	(8,326)	(91)
Balance, December 31, 2009	323,245	3,005	117,053	1,124
Extensions, additions and discoveries	11	—	5	—
Revisions of prior estimates	15,813	123	33,833	353
Production – sales volumes	(24,075)	(267)	(12,455)	(141)
Balance, December 31, 2010	314,994	2,861	138,436	1,336
Extensions, additions and discoveries	175	12	70	5
Revisions of prior estimates	(3,567)	115	(1,583)	76
Production – sales volumes	(21,693)	(249)	(10,661)	(130)
Balance, December 31, 2011	289,909	2,739	126,262	1,287

Extensions, additions and discoveries in 2009, 2010 and 2011 are primarily related to delineation of additional proved undeveloped reserves in the Anadarko Basin. Revisions of prior estimates of the proved gas reserves for the underlying properties in each year are primarily because of changes in the gas and oil prices. Negative revisions of 2011 gas reserves related primarily to increased future costs. Higher upward and downward revisions for the net profits interests as compared with the underlying properties in each year were caused by changes in oil and gas prices and estimated future production and development costs which resulted in an increase or decrease in gas reserves allocated to the trust.

Proved Developed Reserves

	Underlying Properties		Net Profits Interests	
(in thousands)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
December 31, 2008	325,891	2,960	164,080	1,554
December 31, 2009	283,864	2,560	110,050	1,056
December 31, 2010	276,089	2,513	126,349	1,218
December 31, 2011	250,833	2,391	113,312	1,159

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

	December 31		
(in thousands)	2011	2010	2009
Underlying Properties			
Future cash inflows	$1,607,753	$1,619,640	$1,231,607
Future costs:			
Production	717,786	721,736	640,707
Development	67,668	68,201	70,479
Future net cash flows	822,299	829,703	520,421
10% discount factor	403,608	405,114	245,392
Standardized measure	$ 418,691	$ 424,589	$ 275,029
Net Profits Interests			
Future cash inflows	$ 716,607	$ 722,885	$ 453,108
Future production taxes	58,767	59,122	36,771
Future net cash flows	657,840	663,763	416,337
10% discount factor	322,887	324,092	196,314
Standardized measure	$ 334,953	$ 339,671	$ 220,023

Changes in Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)

	2011	2010	2009
Underlying Properties			
Standardized measure, January 1	$424,589	$275,029	$514,750
Revisions:			
Prices and costs	40,475	207,026	(215,257)
Quantity estimates	(9,059)	(1,121)	(24,458)
Accretion of discount	37,013	23,818	44,852
Future development costs	(3,504)	(796)	(16,352)
Production rates and other	(723)	(781)	(1,090)
Net revisions	64,202	228,146	(212,305)
Extensions, additions and discoveries	606	18	10,310
Production	(79,506)	(85,854)	(58,726)
Development costs	8,800	7,250	21,000
Net change	(5,898)	149,560	(239,721)
Standardized measure, December 31	$418,691	$424,589	$275,029
Net Profits Interests			
Standardized measure, January 1	$339,671	$220,023	$411,800
Extensions, additions and discoveries	485	14	8,248
Accretion of discount	29,611	19,054	35,882
Revisions of prior estimates, changes in price and other	21,751	163,463	(205,726)
Net profits income	(56,565)	(62,883)	(30,181)
Standardized measure, December 31	$334,953	$339,671	$220,023

10. Quarterly Financial Data (Unaudited)

The following is a summary of net profits income, distributable income and distributable income per unit by quarter for 2011 and 2010:

	Net Profits Income	Distributable Income	Distributable Income per Unit
2011			
First Quarter	**$13,214,098**	**$12,940,000**	**$0.323500**

Report of Independent Registered Public Accounting Firm

Bank of America, N.A., as Trustee for the Hugoton Royalty Trust:

We have audited the accompanying statement of assets, liabilities, and trust corpus of the Hugoton Royalty Trust as of December 31, 2010 and related statements of distributable income and changes in trust corpus for each of the years in the two-year period ended December 31, 2010. The trustee of Hugoton Royalty Trust is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by the trustee, and evaluating the overall financial statement presentation. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As described in note 2 to the financial statements, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities, and trust corpus of Hugoton Royalty Trust as of December 31, 2010, and its distributable income and changes in trust corpus for each of the years in the two-year period ended December 31, 2010, in conformity with the modified cash basis of accounting described in note 2.

KPMG LLP
Fort Worth, Texas
February 24, 2011

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The trustee conducted an evaluation of the trust's disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, the trustee has concluded that the trust's disclosure controls and procedures were effective as of the end of the period covered by this annual report. In its evaluation of disclosure controls and procedures, the trustee has relied, to the extent considered reasonable, on information provided by XTO Energy.

Trustee's Report on Internal Control Over Financial Reporting

The trustee, Bank of America, N.A., also known as U.S. Trust, Bank of America Private Wealth Management, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934, as amended. The trustee conducted an evaluation of the effectiveness of the trust's internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the trustee's evaluation under the framework in *Internal Control— Integrated Framework*, the trustee concluded that the trust's internal control over financial reporting was effective as of December 31, 2011. The effectiveness of the trust's internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report under Item 8, Financial Statements and Supplementary Data.

Changes in Internal Control Over Financial Reporting

There were no changes in the trust's internal control over financial reporting during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, the trust's internal control over financial reporting.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The trust has no directors, executive officers or audit committee. The trustee is a corporate trustee which may be removed, with or without cause, by the affirmative vote of the holders of a majority of all the units then outstanding.

Section 16(a) of the Securities Exchange Act of 1934 requires that directors, officers, and beneficial owners of more than 10% of the registrant's equity securities file initial reports of beneficial ownership and reports of changes in beneficial ownership with the Securities and Exchange Commission and the New York Stock Exchange. To the trustee's knowledge, based solely on the information furnished to the trustee, the trustee is unaware of any person that failed to file on a timely basis reports required by Section 16(a) filing requirements with respect to the trust units of beneficial interest during and for the year ended December 31, 2011.

Because the trust has no employees, it does not have a code of ethics. Employees of the trustee, U.S. Trust, Bank of America Private Wealth Management, must comply with the bank's code of ethics, a copy of which will be provided to unitholders, without charge, upon request by appointment at Bank of America Plaza, 17th Floor, 901 Main Street, Dallas, Texas 75202.

Item 11. *Executive Compensation*

The trustee received the following annual compensation from 2009 through 2011 as specified in the trust indenture:

Name and Principal Position	Year	Other Annual Compensation[1]
U.S. Trust, Bank of America	2011	$51,936
Private Wealth Management, Trustee	2010	52,563
	2009	48,126

(1) Under the trust indenture, the trustee is entitled to an annual administrative fee, paid in equal monthly installments. Such fee can be adjusted annually based on an oil and gas industry index. Upon termination of the trust, the trustee is entitled to a termination fee of $15,000.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters*

The trust has no equity compensation plans.

(a) *Security Ownership of Certain Beneficial Owners.* The following table sets forth as of February 14, 2012, information with respect to each person known to the trustee to beneficially own more than 5% of the outstanding units:

Name and Address	Amount and Nature of Beneficial Ownership	Percent of Class
Bank of America Corporation 100 North Tryon Street Floor 25 Bank of America Corporate Center Charlotte, NC 28255	2,914,411[1]	7.29%

(1) Bank of America Corporation reports as of December 31, 2011, it directly and on behalf of certain subsidiaries owned 2,914,411 units, of which it had shared voting power with respect to 1,651,766 units and shared dispositive power with respect to 2,914,411 units.

(b) *Security Ownership of Management.* The trust has no directors or executive officers. As of December 31, 2011, Bank of America Corporation and its subsidiaries owned, in various fiduciary capacities, 2,914,411 units, with a

shared right to vote 1,651,766 of these units and shared dispositive power with respect to 2,914,411 of these units. Bank of America, N.A. disclaims any beneficial interests in these units.

(c) *Changes in Control.* The trustee knows of no arrangements which may subsequently result in a change in control of the trust.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

In computing net profits income paid to the trust for the net profits interests, XTO Energy deducts an overhead charge for reimbursement of administrative expenses of operating the underlying properties. This charge at December 31, 2011 was approximately $907,000 per month, or $10,884,000 annually (net to the trust of $725,600 per month or $8,707,200 annually), and is subject to annual adjustment based on an oil and gas industry index as defined in the trust agreement.

XTO Energy sells a significant portion of natural gas production from the underlying properties to certain of its wholly owned subsidiaries under contracts in existence when the trust was created, generally at amounts approximating monthly published prices. For further information, see Item 2, Properties.

See Item 11, Executive Compensation, for the remuneration received by the trustee from 2009 through 2011 and Item 12(b), Security Ownership of Management, for information concerning units owned by the trustee in various fiduciary capacities.

As noted in Item 10, Directors, Executive Officers and Corporate Governance, the trust has no directors, executive officers or audit committee. The trustee is a corporate trustee which may be removed, with or without cause, by the affirmative vote of the holders of a majority of all the units then outstanding.

Item 14. *Principal Accountant Fees and Services*

Fees for services performed by PricewaterhouseCoopers LLP and KPMG LLP for the years ended December 31, 2011 and 2010 are:

	2011	2010
Audit fees-KPMG[(a)]	$ 59,350	$79,900
Audit fees-PwC	$ 50,000	—
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
	$109,350	$79,900

(a) KPMG LLP served as the trust's independent registered public accounting firm through July 7, 2011, and was replaced by PricewaterhouseCoopers LLP effective on that date.

As referenced in Item 10, Directors, Executive Officers and Corporate Governance, above, the trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to PricewaterhouseCoopers LLP or KPMG LLP.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) The following documents are filed as a part of this report:

1. *Financial Statements (included in Item 8 of this report)*

   Report of Independent Registered Public Accounting Firm

   Statements of Assets, Liabilities and Trust Corpus at December 31, 2011 and 2010

   Statements of Distributable Income for the years ended December 31, 2011, 2010 and 2009

   Statements of Changes in Trust Corpus for the years ended December 31, 2011, 2010 and 2009

   Notes to Financial Statements

2. *Financial Statement Schedules*

Financial statement schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. *Exhibits*

(4) (a) Hugoton Royalty Trust Indenture by and between NationsBank, N.A. (now Bank of America, N.A.), as trustee, and Cross Timbers Oil Company (predecessor of XTO Energy) heretofore filed as Exhibit 4.1 to the trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on December 4, 1998, is incorporated herein by reference.

(b) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% - Kansas) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A. (now Bank of America, N.A.), as trustee, dated December 1, 1998, heretofore filed as Exhibit 10.1.1 to the trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

(c) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% - Oklahoma) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A. (now Bank of America, N.A.), as trustee, dated December 1, 1998, heretofore filed as Exhibit 10.1.2 to the trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

(d) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% - Wyoming) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A. (now Bank of America, N.A.), as trustee, dated December 1, 1998, heretofore filed as Exhibit 10.1.3 to the trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

(31) Rule 13a-14(a)/15d-14(a) Certification

(32) Section 1350 Certification

(99.1) Miller and Lents, Ltd. Report

Copies of the above Exhibits are available to any unitholder, at the actual cost of reproduction, upon written request to the trustee, U.S. Trust, Bank of America Private Wealth Management, P.O. Box 830650, Dallas, Texas 75283-0650.

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.

HUGOTON ROYALTY TRUST
By BANK OF AMERICA, N.A., TRUSTEE

By /s/ Nancy G. Willis
Nancy G. Willis
Vice President

EXXON MOBIL CORPORATION

Date: February 29, 2012

By /s/ Patrick T. Mulva
Patrick T. Mulva
Vice President and Controller

(The trust has no directors or executive officers.)

Form 10-K

A copy of the Hugoton Royalty Trust Form 10-K has been provided with this Annual Report. Additional copies of this Annual Report and Form 10-K will be provided to unitholders without charge upon request. Copies of exhibits to the Form 10-K may be obtained upon request or from the trust's web site at www.hugotontrust.com.

Hugoton Royalty Trust
U.S. Trust, Bank of America
Private Wealth Management
P.O. Box 830650
Dallas, Texas 75283-0650
Attention: Annual Reports

(877) 228-5083

Web site

www.hugotontrust.com

Auditors

PricewaterhouseCoopers LLP
Dallas, Texas

Legal and Tax Counsel

Thompson & Knight, L.L.P.
Dallas, Texas

Transfer Agent and Registrar

American Stock Transfer and Trust Company LLC
www.amstock.com

Certification

The Trustee's certification, required by Section 302 of the Sarbanes-Oxley Act of 2002, has been filed as Exhibit 31 of the Trust's Form 10-K, for the fiscal year ended December 31, 2011.

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