# Hugoton Royalty Trust

# 2012

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 2012 and 2011:

| | Sales Price | | Distributions |
|---|---|---|---|
| **2012** | **High** | **Low** | **per Unit** |
| First Quarter | $19.21 | $13.82 | $0.245636 |
| Second Quarter | 14.62 | 6.42 | 0.164046 |
| Third Quarter | 7.90 | 5.71 | 0.053733 |
| Fourth Quarter | 8.56 | 6.21 | 0.118408 |
| | | | $0.581823 |
| **2011** | | | |
| 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 |

At December 31, 2012, there were 40,000,000 units outstanding and approximately 873 unitholders of record.

# The Trust

Hugoton Royalty Trust was created on December 1, 1998 when XTO Energy Inc. conveyed 80% net profits interests in certain predominantly gas-producing properties located in Kansas, Oklahoma and Wyoming to the trust. The net profits interests are the only assets of the trust, other than cash held for trust expenses and for distribution to unitholders.

Net profits income received by the trust on the last business day of each month is calculated and paid by XTO Energy based on net proceeds received from the underlying properties in the prior month. Distributions, as calculated by the trustee, are paid to month-end unitholders of record within ten business days.

# Summary

The trust was created to collect and distribute to unitholders monthly net profits income related to the 80% net profits interests. Such net profits income is calculated as 80% of the net proceeds received from certain working interests in predominantly gas-producing properties in Kansas, Oklahoma and Wyoming. Net proceeds from properties in each state are calculated by deducting production expense, development costs and overhead from revenues. If monthly costs exceed revenues from the underlying properties in any state, such excess costs must be recovered, with accrued interest, from future net proceeds of that state and cannot reduce net profits income from another state. Excess costs generally can occur during periods of higher development activity and/or lower gas prices.

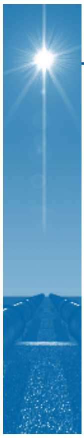
Costs exceeded revenues on properties underlying the Wyoming net profits interests in July 2012, on properties underlying the Kansas net profits interests in September 2012 and on properties underlying the Oklahoma net profits interests in September 2012. The excess costs claimed underlying the Kansas and Oklahoma net profits interests are the subject of pending arbitration described more fully under "Item 3 – Legal Proceedings" of the accompanying Form 10-K. For further information on excess costs, see "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" under Item 7 of the accompanying Form 10-K.

**Cost Depletion** is generally available to unitholders as a deduction from royalty income. Available depletion is dependent upon the unitholder's cost of units, purchase date and prior allowable depletion. It may be more beneficial for unitholders to deduct percentage depletion. Please see the 2012 tax booklet for specific instructions. Unitholders should consult their tax advisors for further information.

# Selected Financial Data

| Years Ended December 31, | 2012 | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Net Profits Income | **$ 25,132,038** | $ 56,565,368 | $ 62,883,206 | $ 30,180,880 | $117,268,069 |
| Distributable Income | **23,272,920** | 55,764,960 | 62,028,000 | 29,306,240 | 116,494,400 |
| Distributable Income per Unit | **0.581823** | 1.394124 | 1.550700 | 0.732656 | 2.912360 |
| Distributions per Unit | **0.581823** | 1.394124 | 1.550700 | 0.732656 | 2.912360 |
| Total Assets at Year End | **$112,956,689** | $118,965,716 | $129,222,886 | $144,162,380 | $147,867,855 |

# To Unitholders:



We are pleased to present the 2012 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, 2012, net profits income totaled $25,132,038. After adding interest income of $508 and deducting trust administration expense of $1,859,626, distributable income was $23,272,920 or $0.581823 per unit. Net profits income and distributions were 56% and 58%, respectively, lower than 2011 amounts primarily because of lower gas prices, decreased oil and gas production and the portion of the Fankhouser settlement deducted in September and October of 2012, partially offset by lower development costs. For further information on the Fankhouser settlement, see below and "Legal Proceedings" under Item 3 of the accompanying Form 10-K.

XTO Energy advised the trustee that on April 23, 2012, it reached a tentative settlement of $37 million in the class action lawsuit styled *Fankhouser v. XTO Energy Inc.* XTO Energy advised the trustee it believes that the terms of the conveyances covering the trust's net profits interests require the trust to bear its 80% interest in the settlement, or approximately $28.5 million, of which $23.4 million will affect the net proceeds from Oklahoma and $5.1 million will affect the net proceeds from Kansas. If so, this will adversely affect the net proceeds of the trust from Oklahoma and Kansas and will result in costs exceeding revenues on these properties. The trustee has advised XTO Energy that all or a portion of the settlement amount should not be deducted from trust revenues and further advised XTO that, notwithstanding the Fankhouser settlement, XTO should make no change in the manner in which it calculates payments to the trust on a go-forward basis. XTO Energy does not agree with the trustee's position, and to resolve this disagreement XTO Energy initiated binding arbitration in accordance with the terms of the dispute resolution provisions of the Trust Indenture. The trustee has filed its response and the hearing is tentatively scheduled for October 7, 2013. For further information on the Fankhouser settlement, please see

# To Unitholders: *Continued*

"Legal Proceedings" under Item 3 of the accompanying Form 10-K.

Natural gas prices averaged $3.28 per Mcf for 2012, 31% lower compared to the 2011 average price of $4.73 per Mcf. The average 2012 oil price was $91.30 per Bbl, 1% higher than the 2011 average price of $90.07 per Bbl.

Gas sales volumes from the underlying properties for 2012 were 20,370,975 Mcf, or 55,658 Mcf per day, a decrease of 6% from 59,433 Mcf per day in 2011. Oil sales volumes from the underlying properties were 228,656 Bbls, or 625 Bbls per day in 2012, a decrease of 8% from 681 Bbls per day in 2011. 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, 2012, proved reserves for the underlying properties were estimated by independent engineers to be 248.2 Bcf of natural gas and 2.5 million Bbls of oil. Natural gas reserves for the underlying properties declined 41.7 Bcf and oil reserves for the underlying properties declined approximately 0.2 million Bbls primarily due to negative revisions to reserves related primarily to lower prices and current year production. Based on an allocation of these reserves, proved reserves attributable to the net profits interests were estimated to be 77.4 Bcf of natural gas and 0.9 million Bbls of oil. Estimated gas and oil reserves attributable to the net profits interests decreased from previously reported reserves at year-end 2011 due to negative revisions to reserves related primarily to lower prices and current year production. All reserve information prepared

# To Unitholders: *Continued*

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, 2012 were $308 million. Using an annual discount factor of 10%, the present value of estimated future net cash flows at December 31, 2012 was $163 million. Proved reserve estimates and related future net cash flows have been determined based on a 12-month average gas price of $3.21 per Mcf and a 12-month average oil price of $91.90 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 2013, 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 8, 2013

# 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, 2012** **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 29, 2012 (the last business day of its most recently completed second fiscal quarter), held by non-affiliates of the registrant on that date was approximately $312 million.

At February 15, 2013, 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**
**2012 ANNUAL REPORT ON FORM 10-K**

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## 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 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:<br>*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 |

## PART I

### Item 1. *Business*

Hugoton Royalty Trust is an express trust created under the laws of Texas pursuant to the Hugoton Royalty Trust Indenture entered into on December 1, 1998 between XTO Energy Inc. (formerly known as Cross Timbers Oil Company), as grantor, and NationsBank, N.A., as trustee. Bank of America, N.A., successor to NationsBank, N.A., is now the trustee of 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 Form 10-K to U.S. Trust, Bank of America Private Wealth Management shall describe the legal entity Bank of America, N.A. The principal office of the trust is located at 901 Main Street, Dallas, Texas 75202 (telephone number 877-228-5083).

The trust's internet web site is www.hugotontrust.com. We make available free of charge, through our web site, our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. These reports are accessible through our internet web site as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

Effective December 1, 1998, XTO Energy conveyed to the trust 80% net profits interests in certain predominantly natural gas producing working interest properties in Kansas, Oklahoma and Wyoming under three separate conveyances. In exchange for these net profits interest conveyances to the trust, 40 million units of beneficial interest were issued to XTO Energy. In April and May 1999, XTO Energy sold a total of 17 million units in the trust's initial public offering. In 1999 and 2000, XTO Energy also sold 1.3 million trust units to certain of its officers. The trust did not receive the proceeds from these sales of trust units. Units are listed and traded on the New York Stock Exchange under the symbol "HGT." In May 2006, XTO Energy distributed all of its remaining 21.7 million trust units as a dividend to its common stockholders. XTO Energy currently is not a unitholder of the trust.

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

The net profits interests entitle the trust to receive 80% of the net proceeds from the sale of oil and gas from the underlying properties. Each month XTO Energy determines the amount of cash received from the sale of production and deducts property and production taxes, production expense, development costs and overhead.

Net proceeds payable to the trust depend upon production quantities, sales prices of oil and gas and costs to develop and produce oil and gas in the prior month. If monthly costs exceed revenues for any of the three conveyances (one for each of the states of Kansas, Oklahoma and Wyoming), such excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net proceeds from other conveyances.

Costs exceeded revenues on properties underlying the Wyoming net profits interests in July 2012, on properties underlying the Kansas net profits interests in September 2012 and on properties underlying the Oklahoma net profits interests in September 2012. The excess costs claimed underlying the Kansas and Oklahoma net profits interests in September 2012 are the subject of pending arbitration described more fully under "Item 3 — Legal Proceedings." For further information on excess costs, see Trustee's Discussion and Analysis of Financial Condition and Results of Operations, under Item 7.

The trust is not liable for any production costs or liabilities attributable to the underlying properties. 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 net profits income payable to the trust for the next month will be reduced by the overpayment, plus interest at the prime rate.

As a working interest owner, XTO Energy can generally decline participation in any operation and allow consenting parties to conduct such operations, as provided under the operating agreements. XTO Energy also can assign, sell, or otherwise transfer its interest in the underlying properties, subject to the net profits interests, or can abandon an underlying property if it is incapable of producing in paying quantities, as determined by XTO Energy.

To the extent allowed, XTO Energy is responsible for marketing its production from the underlying properties under existing sales contracts or new arrangements on the best terms reasonably obtainable in the circumstances. See "Pricing and Sales Information" under Item 2, Properties.

Net profits income received by the trust on or before the last business day of the month is related to net proceeds received by XTO Energy in the preceding month, and is generally attributable to oil and gas production two months prior. The amount to be distributed to unitholders each month by the trustee is determined by:

Adding –

(1) net profits income received,
(2) interest income and any other cash receipts and
(3) cash available as a result of reduction of cash reserves, then

Subtracting –

(1) liabilities paid and
(2) the reduction in cash available related to establishment of or increase in any cash reserve.

The monthly distribution amount is distributed to unitholders of record within ten business days after the monthly record date. The monthly record date is generally the last business day of the month. The trustee calculates the monthly distribution amount and announces the distribution per unit at least ten days prior to the monthly record date.

The trustee may establish cash reserves for contingencies. Cash held for such reserves, as well as for pending payment of the monthly distribution amount, may be invested in federal obligations or certificates of deposit of major banks.

The trustee's function is to collect the net profits income from the net profits interests, to pay all trust expenses, and pay the monthly distribution amount to unitholders. The trustee's powers are specified by the terms of the trust indenture. 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 has no employees since all administrative functions are performed by the trustee.

Approximately 74% of the net profits income received by the trust during 2012, as well as 76% of the estimated proved reserves of the net profits interests at December 31, 2012 (based on estimated future net cash flows using 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period), is attributable to natural gas. There has historically been a greater demand for gas during the winter months than the rest of the year. Otherwise, trust income generally is not subject to seasonal factors, nor dependent upon patents, licenses, franchises or concessions. The trust conducts no research activities.

The oil and gas industry is highly competitive in all its phases. Operators of the properties in which the trust holds interests encounter competition from other oil and gas companies and from individual producers and operators. Oil and natural gas are commodities, for which market prices are determined by external supply and demand factors.

### Item 1A. *Risk Factors*

The following factors could cause actual results to differ materially from those contained in forward-looking statements made in this report and presented elsewhere by the trustee from time to time. Such factors may have a material adverse effect upon the trust's financial condition, distributable income and changes in trust corpus.

The following discussion of risk factors should be read in conjunction with the financial statements and related notes included under Item 8, Financial Statements and Supplementary Data. Because of these and other factors, past financial performance should not be considered an indication of future performance.

***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. Certain claimed production expenses by XTO Energy may reduce or eliminate distributions to unitholders for extended periods of time.***

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 Wyoming net profits interests in July 2012, the Kansas net profits interests in September 2012 and the Oklahoma net profits interests in September 2012), 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. The excess costs claimed by XTO Energy in September 2012 underlying the Kansas and Oklahoma net profits interests relate to settlement payments made by XTO Energy in the Fankhouser v. XTO Energy, Inc. case. Although the issue of whether XTO Energy may deduct all or a portion of the settlement payments from trust proceeds is the subject of a pending arbitration, if XTO Energy is ultimately successful in such arbitration, the deduction of the settlement payments would cause costs to exceed revenues for approximately 12 months on properties underlying the Oklahoma net profits interests and by approximately 7 years on properties underlying the Kansas net profits interests; however, changes in oil or natural gas prices or expenses could cause the time period to increase or decrease correspondingly. See "Item 3 — Legal Proceedings" for additional information.

***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, 2012, 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, 2012 is approximately 13 years. This index is calculated using total proved reserves and estimated 2013 production for the underlying properties. The projected 2013 production is from proved developed producing reserves as of December 31, 2012. 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 78% natural gas and 22% 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 2012 development costs deducted for the underlying properties were $6 million, a decrease of 32% from the prior year. XTO Energy has informed the trustee that total 2013 budgeted development costs for the underlying properties are between $6 million and $8 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 2012, daily sales volumes from the underlying properties in the Hugoton area averaged approximately 15,000 Mcf of gas and 58 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 2013.

Within this area, XTO Energy did not drill any wells or perform any workovers in 2012. XTO Energy has informed the trustee that it does not plan to drill any new wells but may perform up to 20 workovers during 2013.

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 11,000 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 25,500 Mcf of gas and 539 Bbls of oil in 2012.

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 (0.6 net) well and performed 46 workovers in 2012. XTO Energy has informed the trustee that does not plan to drill any new wells but may perform up to 14 workovers in Major County during 2013.

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 but did perform 3 workovers in 2012. XTO Energy has informed the trustee that it does not plan to drill any new wells but may perform up to 3 workovers in Woodward County during 2013.

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 2012. XTO Energy has informed the trustee that does not plan to drill any new wells but may perform up to 6 workovers within the Elk City field during 2013.

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 2012, the gathering system collected approximately 9,000 Mcf per day, approximately 53% 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 6,000 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 2012 sales volumes from the underlying properties in the Fontenelle field averaged 15,200 Mcf of natural gas and 28 Bbls of oil. XTO Energy did not drill any wells or perform any workovers in the Green River Basin in 2012. 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 2013. 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 2012, the fuel charge was 1.80% 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, 2012. Undeveloped acreage is not significant.

| | Gross | Net |
|---|---|---|
| Hugoton Area | 211,688 | 196,662 |
| Anadarko Basin | 172,215 | 133,301 |
| Green River Basin | 37,912 | 28,626 |
| Total | 421,815 | 358,589 |

The following is a summary of the producing wells on the underlying properties as of December 31, 2012:

| | Operated Wells | | Nonoperated Wells | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Gas | 1,218.0 | 1,080.3 | 291.0 | 65.4 | 1,509.0 | 1,145.7 |
| Oil | 51.0 | 45.7 | 5.0 | 0.9 | 56.0 | 46.6 |
| Total | 1,269.0 | 1,126.0 | 296.0 | 66.3 | 1,565.0 | 1,192.3 |

The following is a summary of the number of wells drilled on the underlying properties during the years indicated. During 2012 and 2010 no exploratory wells were drilled on the underlying properties. During 2011, one exploratory dry hole (0.0 net) was drilled on the underlying properties. All other wells drilled were developmental. There were no wells in process of drilling at December 31, 2012.

| | 2012 | | 2011 | | 2010 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Completed gas wells | 1 | 0.6 | 3 | 1.5 | 3 | 2.7 |
| Completed oil wells | — | — | — | — | — | — |
| Dry wells | — | — | 1 | — | — | — |
| Total(a) | 1 | 0.6 | 4 | 1.5 | 3 | 2.7 |

(a) Included in totals are zero wells in 2012, 3 gross (0.5 net) wells in 2011 and zero wells in 2010, 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, 2012:

| | 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 | 169,901 | 2,330 | 59,626 | 822 | $259,045 | $135,589 |
| Wyoming | 59,834 | 68 | 11,539 | 13 | 27,348 | 14,234 |
| Kansas | 18,446 | 115 | 6,191 | 40 | 21,525 | 12,820 |
| TOTAL | 248,181 | 2,513 | 77,356 | 875 | $307,918 | $162,643 |

(a) Based on 12-month average oil price of $91.90 per Bbl and $3.21 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 51% from year-end 2011 to 2012, primarily because of a 30% decrease in natural gas 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:

| (in thousands) | Underlying Properties Proved Reserves Gas (Mcf) | Underlying Properties Proved Reserves Oil (Bbls) | Net Profits Interests Proved Reserves Gas (Mcf) | Net Profits Interests Proved Reserves Oil (Bbls) |
|---|---|---|---|---|
| Proved developed reserves | 211,638 | 2,192 | 71,327 | 806 |
| Proved undeveloped reserves | 36,543 | 321 | 6,029 | 69 |
| Total proved reserves | 248,181 | 2,513 | 77,356 | 875 |

Approximately 85% 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, 2012, 2011, 2010 and 2009. 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:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Production** | | | |
| *Underlying Properties* | | | |
| Gas – Sales (Mcf) | **20,370,975** | 21,693,139 | 24,074,923 |
| Average per day (Mcf) | **55,658** | 59,433 | 65,959 |
| Oil – Sales (Bbls) | **228,656** | 248,739 | 266,656 |
| Average per day (Bbls) | **625** | 681 | 731 |
| *Net Profits Interests* | | | |
| Gas – Sales (Mcf) | **5,991,964** | 10,661,323 | 12,455,292 |
| Average per day (Mcf) | **16,371** | 29,209 | 34,124 |
| Oil – Sales (Bbls) | **76,049** | 130,109 | 140,544 |
| Average per day (Bbls) | **208** | 356 | 385 |
| **Average Sales Price** | | | |
| Gas (per Mcf) | **$ 3.28** | $ 4.73 | $ 4.72 |
| Oil (per Bbl) | **$91.30** | $90.07 | $73.77 |

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** | **2012** | **2011** | **2010** |
| Kansas | **1,805,789** | 2,007,032 | 2,323,436 |
| Oklahoma | **12,992,317** | 13,858,590 | 15,268,280 |
| Wyoming | **5,572,869** | 5,827,517 | 6,483,207 |
| Total | **20,370,975** | 21,693,139 | 24,074,923 |

| | Underlying Oil Production (Bbls) | | |
|---|---|---|---|
| **Conveyance** | **2012** | **2011** | **2010** |
| Kansas | **14,090** | 20,682 | 34,462 |
| Oklahoma | **204,022** | 216,287 | 220,149 |
| Wyoming | **10,544** | 11,770 | 12,045 |
| Total | **228,656** | 248,739 | 266,656 |

### 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 2013. 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 that 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 2012, the trust incurred administration expenses and 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 the adjusted basis of such property includes adjustments for depletion deductions under Section 611 of the Internal Revenue Code (the "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.

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 39.6%, and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) and qualified dividends of individuals is 20%. Such marginal tax rates may be effectively increased by up to 1.2% due to the phaseout of personal exemptions and the limitations on itemized deductions. The highest marginal U.S. federal income tax rate applicable to corporations is 35%, and such rate applies to both ordinary income and capital gains.

Section 1411 of the Code imposes a 3.8% Medicare tax on certain investment income earned by individuals, estates, and trusts for taxable years beginning after December 31, 2012. For these purposes, investment income generally will include a unitholder's allocable share of the trust's interest and royalty income plus the gain recognized from a sale of trust units. In the case of an individual, the tax is imposed on the lesser of (i) the individual's net investment income from all investments, or (ii) the amount by which the individual's modified adjusted gross income exceeds specified threshold levels depending on such individual's federal income tax filing status. In the case of an estate or trust, the tax is imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

Pending the outcome of arbitration proceedings between the trust and XTO, the trust may be required to bear a portion of the legal settlement costs arising from the Fankhouser settlement (discussed in Part I, Item 3, Legal Proceedings). In the event that the trust is determined to be responsible for such costs, XTO will deduct the costs in its calculation of the net profits income payable to the trust from the applicable net profits interests. Thus, for unitholders, the legal settlement costs will be reflected through a reduction in net profits income received from the trust and thus in a reduction in the gross royalty income reported by and taxable to the unitholders. In addition to the potential settlement costs, the trustee has also incurred legal fees in representing the trust's interests in the ongoing arbitration. For unitholders, such costs will be reflected through an increase in the trust's administrative expenses, which are deductible by unitholders in determining the net royalty income from the trust.

Individuals may also incur expenses in connection with the acquisition or maintenance of trust units. These expenses, which are different from a unitholder's share of the trust's administrative expenses discussed above, may be deductible as "miscellaneous itemized deductions" only to the extent that such expenses exceed 2 percent of the individual's gross income.

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 Kansas, Oklahoma or Wyoming. Kansas and Oklahoma each impose a state income tax, which is potentially applicable to income from the net profits interests located in each of those states. 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 taxes the income of nonresidents from real property located within the state, and the trust has been advised by counsel that Oklahoma will tax nonresidents on income from the net profits interest located within the state. Kansas also taxes the income of nonresidents from property located within the state. However, for tax years beginning after December 31, 2012, Kansas allows individuals to deduct certain amounts, including net income from royalties reported on schedule E of their Form 1040 federal individual income tax return, from their federal adjusted gross income when calculating their Kansas taxable income. This deduction applies to amounts reported as royalty income that are received from grantor trusts, such as the trust. 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).

Wyoming does not have a state income tax.

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 were filed by the parties and ruled on by the court. XTO Energy has informed the trustee that after consideration of the rulings by the court in March and April of 2012, some benefiting XTO Energy and some benefiting the plaintiffs, and with due regard to the vagaries of litigation and their uncertain outcomes, XTO Energy and the plaintiffs entered into settlement negotiations prior to trial and reached a tentative settlement of $37 million on April 23, 2012. XTO has advised the trustee that $1.4 million of the settlement is attributable to Kansas claims which predate the Trust and therefore XTO Energy will not charge to the Trust. The settlement also includes a new royalty calculation for future royalty payments. The hearing for formal court approval was conducted on June 21, 2012 and preliminarily approved by the court on June 29, 2012. A fairness hearing was conducted on October 10, 2012 and the settlement was given final approval by the court. The court's order sets out the amount of attorneys' fees and costs awarded to the plaintiffs' counsel from the $37 million settlement. A third party administrator will make the distribution to the royalty owners as set out in the order approving the settlement.

XTO Energy has advised the trustee it believes that the terms of the conveyances covering the trust's net profits interests require the trust to bear its 80% interest in the settlement, or approximately $28.5 million, of which $23.4 million will affect the net proceeds from Oklahoma and $5.1 million will affect the net proceeds from Kansas. If so, this will adversely affect the net proceeds of the trust from Oklahoma and Kansas and will result in costs exceeding revenues on these properties. XTO Energy began deducting the settlement amount with the September 2012 distribution. Based on the revised settlement allocation between Oklahoma and Kansas and recent revenue and expense levels, the deductions XTO Energy has made, and will resume making if the Tribunal ultimately rules in XTO Energy's favor, will cause costs to exceed revenues for approximately 12 months on properties underlying the Oklahoma net profits interests and by approximately 7 years on properties underlying the Kansas net profits interests; however, changes in oil or natural gas prices or expenses could cause the time period to increase or decrease correspondingly. The net profits interest from Wyoming is unaffected and payments will continue to be made from those properties to the extent revenues exceed costs on such properties. XTO Energy has advised the trustee that the settlement would decrease the amount of net profits going forward for the Oklahoma and Kansas properties due to changes in the way costs (such as gathering, compression and fuel) associated with operating the properties will be allocated, resulting in a net gain to the royalty interest owners. XTO Energy has advised the trustee that this expected net upward revision for the royalty interest owners would reduce applicable net profits to XTO Energy and, correspondingly, to the trust. For 2012 the revision would have reduced trust net proceeds by approximately $272,000 (which amount would have been reflected in the June 2012 through December 2012 distributions).

The trustee has advised XTO Energy that all or a portion of the settlement amount should not be deducted from trust revenues. The trustee further advised XTO that, notwithstanding the Fankhouser settlement, XTO should make no change in the manner in which it calculates payments to the trust on a go-forward basis. XTO Energy does not agree with the trustee's position, and to resolve this disagreement XTO Energy initiated binding arbitration on August 1, 2012 in accordance with the terms of the dispute resolution provisions of the Trust Indenture. On August 17, 2012 the trustee filed its response to XTO's arbitration claim. All issues in the arbitration will be decided by a panel of three arbitrators (the "Tribunal"). Each side selected one arbitrator and the third arbitrator was selected by the other two appointed arbitrators. The arbitration will be administered by the American Arbitration Association under its commercial rules. The arbitration hearing is tentatively scheduled for October 7, 2013 in Fort Worth, Texas if not sooner disposed of by the parties by agreement or by the Tribunal on motion. Because XTO Energy advised the trustee that it began deducting the settlement in September, the trustee reserved a total of $900,000 from trust distributions to help fund potential legal and other expenses relating to the arbitration. The trustee believed that without such a reserve, the trust was likely to be left without adequate resources to fund the costs of the arbitration out of monthly trust revenues. Because the potential expenses of arbitration are uncertain, especially at this early stage of the arbitration, it is possible that the reserve may not be sufficient to cover all of such expenses.

The trustee requested that the Tribunal enjoin XTO Energy from continuing to deduct the Fankhouser settlement amount while the arbitration is pending. A hearing on the injunction was held on October 27, 2012. The Tribunal ordered that pending the issuance of a final award or further order of the Tribunal, XTO Energy should not treat any costs or expenses associated with the Fankhouser settlement as chargeable against the trust's net profit interest under the conveyances. The Tribunal denied the trust's request for an interim order directing XTO Energy to pay the trust the amounts offset against the trust's September and October 2012 distributions on the basis of the Fankhouser litigation. Based on this decision, deductions associated with the Fankhouser settlement were suspended starting in November 2012. XTO Energy has also informed the trustee that during the pendency of this action, no adjustment will be made to the net profits to the trust on a go-forward basis based on the changes in the way costs will be allocated to royalty owners in accordance with the Fankhouser settlement.

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. The case was certified as a class action in March 2012. XTO Energy has filed an appeal of the class certification to the 10th Circuit Court of Appeals on April 11, 2012, believing the class certification was not proper. The appeal was granted on June 26, 2012. The matter has been fully briefed, and oral argument is scheduled for May 8, 2013. The court will rule at a time of its discretion.

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*. The case was certified as a class action in April 2012. XTO Energy has filed an appeal of the class certification to the 10th Circuit Court of Appeals on April 26, 2012, believing the class certification was not proper. The appeal was granted on June 26, 2012. The matter has been fully briefed, and oral argument is scheduled for May 8, 2013. The court will rule at a time of its discretion.

XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to these lawsuits and intends to vigorously defend its position. However, XTO Energy is cognizant of other, similar litigation involving it, such as *Fankhouser*, and other, unrelated entities. As these cases develop XTO Energy will assess its legal position accordingly. If XTO Energy ultimately makes any settlement payments or receives a judgment against it in *Chieftain* or *Roderick*, XTO Energy has advised the trustee that it believes that the terms of the conveyances covering the trust's net profits interests require the trust to 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, XTO Energy has informed the trustee that the trust would bear its proportionate share of the increased payments through reduced net proceeds. In the event of any such settlement or judgment, the trustee intends to review any claimed reductions in payment to the trust based on the facts and circumstances of such settlement or judgment. 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, XTO Energy has advised the trustee that any reductions would result in costs exceeding revenues on the properties underlying the net profit interests of the cases named above, as applicable, for several monthly distributions, depending on the size of the judgment or settlement, if any, and the net proceeds being paid at that time, which would result in the net profits interest being limited until such time that the revenues exceed the costs for those net profit interests. If there is a settlement or judgment and should XTO Energy and the trustee disagree concerning the amount of the settlement or judgment to be charged against the trust's net profits interests, the matter will be resolved by binding arbitration under the terms of the Indenture creating the trust through the American Arbitration Association.

On September 12, 2012, a lawsuit was filed against Bank of America as trustee and XTO Energy styled *Harold Lamb v. Bank of America and XTO Energy Inc.,* in the U.S. District Court—Western District of Oklahoma. The plaintiff, Harold Lamb, is a unitholder in the trust and alleges that XTO Energy failed to properly pay and account to the trust under the terms of the net overriding royalty conveyance on certain Kansas and Oklahoma properties and that Bank of America, as trustee, failed to properly oversee such payment and accounting by XTO Energy. Additionally, the plaintiff alleges that Bank of America and XTO Energy have breached a fiduciary duty to the trust based on the allegations found in the *Fankhouser* class action discussed above. The plaintiffs are seeking unspecified amounts for actual/compensatory damages, punitive damages, disgorgement and injunctive relief. Subsequently, the plaintiff dismissed Bank of America from the lawsuit. The court granted XTO Energy's motion to transfer venue and has transferred the case to the U.S. District Court for the Northern District of Texas. XTO has also filed two motions to dismiss. XTO Energy has informed the trustee that it believes it has strong defenses to this lawsuit and intends to vigorously defend its position. However, XTO Energy is cognizant of other, similar litigation involving it, such as *Fankhouser*, and other, unrelated entities. As this case develops XTO Energy will assess its legal position accordingly.

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 the financial position or liquidity of the trust, but may have an effect on annual distributable income.

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

Not Applicable.

## PART II

### Item 5. *Market for Units of the Trust, Related Untiholder Matters and Trust Purchases of Units*

**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 2012 and 2011:

| Quarter | Sales Price High | Sales Price Low | Distributions per Unit |
|---|---|---|---|
| **2012** | | | |
| **First** | **$19.21** | **$13.82** | **$0.245636** |
| **Second** | **14.62** | **6.42** | **0.164046** |
| **Third** | **7.90** | **5.71** | **0.053733** |
| **Fourth** | **8.56** | **6.21** | **0.118408** |
| | | | **$0.581823** |
| 2011 | | | |
| First | $24.67 | $20.31 | $0.323500 |
| Second | 24.25 | 21.35 | 0.360069 |
| Third | 23.84 | 19.51 | 0.383334 |
| Fourth | 22.53 | 18.71 | 0.327221 |
| | | | $1.394124 |

At December 31, 2012, there were 40,000,000 units outstanding and approximately 873 unitholders of record; 37,775,743 of these units were held by depository institutions.

The trust has no equity compensation plans, nor has it purchased any units during the period covered by this report.

### Item 6. *Selected Financial Data*

| | Year Ended December 31 2012 | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Net Profits Income | **$ 25,132,038** | $ 56,565,368 | $ 62,883,206 | $ 30,180,880 | $117,268,069 |
| Distributable Income | **23,272,920** | 55,764,960 | 62,028,000 | 29,306,240 | 116,494,400 |
| Distributable Income per Unit | **0.581823** | 1.394124 | 1.550700 | 0.732656 | 2.912360 |
| Distributions per Unit | **0.581823** | 1.394124 | 1.550700 | 0.732656 | 2.912360 |
| Total Assets at Year-End | **112,956,689** | 118,965,716 | 129,222,886 | 144,162,380 | 147,867,855 |

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

**Calculation of Net Profits Income**

The following is a summary of the calculation of net profits income received by the trust:

| | Year Ended December 31[a] | | | Three Months Ended December 31[a] | |
|---|---|---|---|---|---|
| | **2012** | **2011** | **2010** | **2012** | **2011** |
| **Sales Volumes** | | | | | |
| Gas (Mcf)[b] | | | | | |
| Underlying properties | **20,370,975** | 21,693,139 | 24,074,923 | **5,244,376** | 5,240,868 |
| Average per day | **55,658** | 59,433 | 65,959 | **57,004** | 56,966 |
| Net profits interests | **5,991,964** | 10,661,323 | 12,455,292 | **1,325,777** | 2,552,362 |
| Oil (Bbls)[b] | | | | | |
| Underlying properties | **228,656** | 248,739 | 266,656 | **55,772** | 58,027 |
| Average per day | **625** | 681 | 731 | **606** | 631 |
| Net profits interests | **76,049** | 130,109 | 140,544 | **15,120** | 30,775 |
| **Average Sales Prices** | | | | | |
| Gas (per Mcf) | **$3.28** | $4.73 | $4.72 | **$3.28** | $4.70 |
| Oil (per Bbl) | **$91.30** | $90.07 | $73.77 | **$86.92** | $83.12 |
| **Revenues** | | | | | |
| Gas sales | **$ 66,738,058** | $102,621,117 | $113,571,616 | **$17,206,796** | $24,654,439 |
| Oil sales | **20,875,782** | 22,405,023 | 19,670,776 | **4,847,434** | 4,823,102 |
| Total Revenues | **87,613,840** | 125,026,140 | 133,242,392 | **22,054,230** | 29,477,541 |
| **Costs** | | | | | |
| Taxes, transportation and other | **10,983,543** | 13,613,297 | 15,224,494 | **2,886,081** | 3,333,833 |
| Production expense | **22,596,750** | 21,103,426 | 21,086,979 | **5,253,599** | 5,447,418 |
| Development costs[c] | **6,000,000** | 8,800,000 | 7,250,000 | **1,500,000** | 1,500,000 |
| Overhead | **11,135,189** | 10,802,707 | 10,974,111 | **2,858,695** | 2,688,757 |
| Legal Expense[d] | **35,601,400** | – | – | **–** | – |
| Excess costs[d] | **(30,118,090)** | – | 102,800 | **3,342,186** | – |
| Total Costs | **56,198,792** | 54,319,430 | 54,638,384 | **15,840,561** | 12,970,008 |
| **Net Proceeds** | **31,415,048** | 70,706,710 | 78,604,008 | **6,213,669** | 16,507,533 |
| **Net Profits Percentage** | **80%** | 80% | 80% | **80%** | 80% |
| **Net Profits Income** | **$ 25,132,038** | $ 56,565,368 | $ 62,883,206 | **$ 4,970,935** | $13,206,026 |

(a) Because of the two-month interval between time of production and receipt of net profits income by the trust: 1) oil and gas sales for the year ended December 31 generally relate to twelve months of production for the period November through October, and 2) oil and gas sales for the three months ended December 31 generally relate to production for the period August through October.

(b) Oil and gas sales volumes are allocated to the net profits interests based upon a formula that considers oil and gas prices and the total amount of production expense and development costs. As product prices change, the trust's share of the production volumes is impacted as the quantity of production to cover expenses in reaching the net profits break-even level changes inversely with price. As such, the underlying property production volume changes may not correlate with the trust's net profit share of those volumes in any given period. Therefore, comparative discussion of oil and gas sales volumes is based on the underlying properties.

(c) See Note 5 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

(d) See Note 4 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

## Results of Operations

### Years Ended December 31, 2012, 2011 and 2010

Net profits income for 2012 was $25,132,038, as compared with $56,565,368 for 2011 and $62,883,206 for 2010. The 56% decrease in net profits income from 2011 to 2012 is primarily the result of lower gas prices ($25.2 million), decreased oil and gas production ($5.0 million) and the portion of the Fankhouser settlement deducted in September and October of 2012 ($4.4 million), partially offset by lower development costs ($2.2 million). 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). Approximately 74% in 2012, 81% in 2011 and 85% in 2010 of net profits income was derived from natural gas sales.

Trust administration expense was $1,859,626 in 2012 as compared to $801,563 in 2011 and $856,314 in 2010. Included in 2012 administration expense is $900,000 which the trustee has reserved for legal expenses regarding the Fankhouser class action settlement. Interest income was $508 in 2012, $1,155 in 2011 and $1,108 in 2010. Changes in interest income are attributable to fluctuations in net profits income and interest rates. Distributable income was $23,272,920 or $0.581823 per unit in 2012, $55,764,960 or $1.394124 per unit in 2011 and $62,028,000 or $1.550700 per unit in 2010.

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 2011 to 2012, underlying gas sales volumes decreased 6% and underlying oil sales volumes decreased 8% primarily due to natural production decline. 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.

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

#### *Prices*

*Gas.* The 2012 average gas price was $3.28 per Mcf, a 31% decrease from the 2011 average gas price of $4.73 per Mcf, which was relatively flat from the 2010 average gas price of $4.72 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 2012 through January 2013 was $3.51 per MMBtu. At February 11, 2013, the average NYMEX gas price for the following 12 months was $3.63 per MMBtu.

*Oil*. The average oil price for 2012 was $91.30 per Bbl, 1% higher than the average oil price for 2011 of $90.07 per Bbl, which was 22% higher than the average oil price for 2010 of $73.77 per Bbl. Oil prices are expected to remain volatile. The average NYMEX price for November 2012 through January 2013 was $89.87 per Bbl. At February 11, 2013, the average NYMEX oil price for the following 12 months was $98.17 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 19% from 2011 to 2012 primarily because of decreased gas production taxes and other deductions related to lower gas revenues, partially offset by increased property taxes related to increased valuations. 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.

*Production expense.* Production expense increased 7% from 2011 to 2012 primarily because increased labor, repairs and maintenance costs and mechanical and marketing rebates included in 2011, partially offset by decreased fuel costs. 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.

*Development costs.* Development costs deducted were $6.0 million in 2012, $8.8 million in 2011 and $7.3 million in 2010. In 2012, actual development costs were $8.7 million. At December 31, 2012, cumulative actual costs exceeded cumulative budgeted costs by approximately $0.3 million. The monthly development cost deduction was $500,000 from the September 2009 distribution 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 through the end of 2012. For further information on 2013 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 $114,245 ($91,396 net to the trust) on properties underlying the Wyoming net profits interests in July 2012. Lower gas prices and increased production expenses related to the timing of cash disbursements caused costs to exceed revenues on properties underlying the Wyoming net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyances. XTO advised the trustee that increased gas prices and decreased production expenses led to the full recovery of excess costs, plus accrued interest of $314 ($251 net to the trust) in August 2012.

XTO advised the trustee in September 2012 that it deducted $35,601,400 ($28,481,120 net to the trust) related to the Fankhouser settlement. The settlement deduction caused costs to exceed revenues by $27,235,464 ($21,788,371 net to the trust) on properties underlying the Oklahoma net profits interests and by $6,225,126 ($4,980,101 net to the trust) on properties underlying the Kansas net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyance. XTO advised the trustee in October 2012 that it partially recovered $3,342,186 ($2,673,749 net to the trust) of excess costs. Remaining excess costs at December 31, 2012 were $24,027,648 ($19,222,118 net to the trust) on properties underlying the Oklahoma net profits interests and $6,090,756 ($4,872,605 net to the trust) on properties underlying the Kansas net profits interests. The excess costs claimed underlying the Kansas and Oklahoma net profits interests are the subject of pending arbitration described more fully under "Item 3 — Legal Proceedings." See Note 9 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

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.

**Fourth Quarter 2012 and 2011**

During fourth quarter 2012 the trust received net profits income totaling $4,970,935 compared with fourth quarter 2011 net profits income of $13,206,026. This 62% decrease in net profits income was primarily due to lower gas prices ($6.0 million) and the portion of the Fankhouser settlement deducted in October of 2012 ($2.7 million), partially offset by decreased taxes transportation and other costs ($0.4 million).

Administration expense was $234,667 and interest income was $52, resulting in fourth quarter 2012 distributable income of $4,736,320 or $0.118408 per unit. Distributable income for fourth quarter 2011 was $13,088,840 or $0.327221 per unit.

Distributions to unitholders for the quarter ended December 31, 2012 were:

| Record Date | Payment Date | Per Unit |
|---|---|---|
| October 31, 2012 | November 15, 2012 | $0.006083 |
| November 30, 2012 | December 14, 2012 | 0.052847 |
| December 31, 2012 | January 15, 2013 | 0.059478 |
| | | $0.118408 |

***Volumes***

Fourth quarter underlying gas sales volumes remained relatively flat and underlying oil sales volumes decreased 4% from 2011 to 2012. Gas sales volumes remained relatively flat as increased production resulting from 2011 scheduled maintenance on a gathering and processing system in the Hugoton area and the timing of cash receipts were offset by natural production decline. Oil sales volumes decreased primarily because of natural production decline.

***Prices***

The average fourth quarter 2012 gas price was $3.28 per Mcf, or 30% lower than the fourth quarter 2011 average price of $4.70 per Mcf. The average fourth quarter 2012 oil price was $86.92 per Bbl, or 5% higher than the fourth quarter 2011 average price of $83.12 per Bbl. For further information about product prices, see "Years Ended December 31, 2012, 2011 and 2010 – Prices" above.

***Costs***

*Taxes, transportation and other.* Taxes, transportation and other decreased 13% from fourth quarter 2011 to 2012 primarily because of decreased gas production taxes and other deductions related to lower gas revenues, partially offset by increased property taxes related to increased valuations.

*Production expense.* Fourth quarter production expense decreased 4% from 2011 to 2012 primarily because of decreased fuel, repairs and maintenance and outside operated costs, partially offset by increased labor and location costs.

*Development costs*. Development costs, which were deducted based on budgeted development costs, remained flat from fourth quarter 2011 to 2012.

*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.* XTO advised the trustee in September 2012 that it deducted $35,601,400 ($28,481,120 net to the trust) related to the Fankhouser settlement. The settlement deduction caused costs to exceed revenues by $27,235,464 ($21,788,371 net to the trust) on properties underlying the Oklahoma net profits interests and by $6,225,126 ($4,980,101 net to the trust) on properties underlying the Kansas net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyance. XTO advised the trustee in October 2012 that it partially recovered $3,342,186 ($2,673,749 net to the trust) of excess costs. Remaining excess costs at December 31, 2012 were $24,027,648 ($19,222,118 net to the trust) on properties underlying the Oklahoma net profits interests and $6,090,756 ($4,872,605 net to the trust) on properties underlying the Kansas net profits interests. The excess costs claimed underlying the Kansas and Oklahoma net profits interests are the subject of pending arbitration described more fully under "Item 3 – Legal Proceedings." See Note 9 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

**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, 2012, other than the December distribution payable to unitholders in January 2013, 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 | $2,379,120 | $2,379,120 | $— | $— | $— |

**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, 2012, the monthly overhead charge, based on the number of operated wells, was approximately $967,000 ($773,600 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 $22.3 million for 2012, or 34% of total gas sales, $35.6 million for 2011, or 35% of total gas sales and $48.5 million for 2010, or 43% 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, and year end costs for estimated future development and production expenditures. 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***


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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 | |
|---|---|---|
| | **2012** | **2011** |
| Assets | | |
| Cash and short-term investments | **$ 3,063,712** | $ 3,597,720 |
| Net profits interests in oil and gas properties — net (Notes 1 and 2) | **109,892,977** | 115,367,996 |
| | **$112,956,689** | $118,965,716 |
| Liabilities and Trust Corpus | | |
| Distribution payable to unitholders | **$ 2,379,120** | $ 3,597,720 |
| Legal reserve | **684,592** | — |
| Trust corpus (40,000,000 units of beneficial interest authorized and outstanding) | **109,892,977** | 115,367,996 |
| | **$112,956,689** | $118,965,716 |

### STATEMENTS OF DISTRIBUTABLE INCOME

| | Year Ended December 31 | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| Net profits income | **$25,132,038** | $56,565,368 | $62,883,206 |
| Interest income | **508** | 1,155 | 1,108 |
| Total income | **25,132,546** | 56,566,523 | 62,884,314 |
| Administration expense | **1,859,626** | 801,563 | 856,314 |
| Distributable income | **$23,272,920** | $55,764,960 | $62,028,000 |
| Distributable income per unit (40,000,000 units) | **$ 0.581823** | $ 1.394124 | $ 1.550700 |

### STATEMENTS OF CHANGES IN TRUST CORPUS

| | Year Ended December 31 | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| Trust corpus, beginning of year | **$115,367,996** | $124,993,766 | $139,877,580 |
| Amortization of net profits interests | **(5,475,019)** | (9,625,770) | (14,883,814) |
| Distributable income | **23,272,920** | 55,764,960 | 62,028,000 |
| Distributions declared | **(23,272,920)** | (55,764,960) | (62,028,000) |
| Trust corpus, end of year | **$109,892,977** | $115,367,996 | $124,993,766 |

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 trustee routinely reviews the trust's net profits interests in oil and gas properties for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If an impairment event occurs and it is determined that the carrying value of the trust's net profits interests may not be recoverable, an impairment will be recognized as measured by the amount by which the carrying amount of the net profits interests exceeds the fair value of these assets, which would likely be measured by discounting projected cash flows. There is no impairment of the assets as of December 31, 2012.

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 $137,173,974 as of December 31, 2012 and $131,698,955 as of December 31, 2011.

### 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 $114,245 ($91,396 net to the trust) on properties underlying the Wyoming net profits interests in July 2012. Lower gas prices and increased production expenses related to the timing of cash disbursements caused costs to exceed revenues on properties underlying the Wyoming net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyances. XTO advised the trustee that increased gas prices and decreased production expenses led to the full recovery of excess costs, plus accrued interest of $314 ($251 net to the trust) in August 2012.

XTO advised the trustee in September 2012 that it deducted $35,601,400 ($28,481,120 net to the trust) related to the Fankhouser settlement. The settlement deduction caused costs to exceed revenues by $27,235,464 ($21,788,371 net to the trust) on properties underlying the Oklahoma net profits interests and by $6,225,126 ($4,980,101 net to the trust) on properties underlying the Kansas net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyance. XTO advised the trustee in October 2012 that it partially recovered $3,342,186 ($2,673,749 net to the trust) of excess costs. Remaining excess costs at December 31, 2012 were $24,027,648 ($19,222,118 net to the trust) on properties underlying the Oklahoma net profits interests and $6,090,756 ($4,872,605 net to the trust) on properties underlying the Kansas net profits interests (Note 9). The excess costs claimed underlying the Kansas and Oklahoma net profits interests are the subject of pending arbitration described more fully under (Note 9).

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.

## 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 | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| Cumulative actual costs under (over) the amount deducted – beginning of period | **$ 2,396,920** | $ (809,696) | $ 909,477 |
| Actual costs | **(8,698,842)** | (5,593,384) | (8,969,173) |
| Budgeted costs deducted | **6,000,000** | 8,800,000 | 7,250,000 |
| Cumulative actual costs (over) under the amount deducted – end of period | **$ (301,922)** | $ 2,396,920 | $ (809,696) |

The monthly development cost deduction was $500,000 from the September 2009 distribution 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 through the end of 2012. For further information on 2013 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 (over) under 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 that 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 2012, the trust incurred administration expenses and 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 the adjusted basis of such property includes adjustments for depletion deductions under Section 611 of the 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.

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 39.6%, and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) and qualified dividends of individuals is 20%. Such marginal tax rates may be effectively increased by up to 1.2% due to the phaseout of personal exemptions and the limitations on itemized deductions. The highest marginal U.S. federal income tax rate applicable to corporations is 35%, and such rate applies to both ordinary income and capital gains.

Section 1411 of the Code imposes a 3.8% Medicare tax on certain investment income earned by individuals, estates, and trusts for taxable years beginning after December 31, 2012. For these purposes, investment income generally will include a unitholder's allocable share of the trust's interest and royalty income plus the gain recognized from a sale of trust units. In the case of an individual, the tax is imposed on the lesser of (i) the individual's net investment income from all investments, or (ii) the amount by which the individual's modified adjusted gross income exceeds specified threshold levels depending on such individual's federal income tax filing status. In the case of an estate or trust, the tax is imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

Pending the outcome of arbitration proceedings between the trust and XTO, the trust may be required to bear a portion of the legal settlement costs arising from the Fankhouser settlement (discussed in Part I, Item 3, Legal Proceedings). In the event that the trust is determined to be responsible for such costs, XTO will deduct the costs in its calculation of the net profits income payable to the trust from the applicable net profits interests. Thus, for unitholders, the legal settlement costs will be reflected through a reduction in net profits income received from the trust and thus in a reduction in the gross royalty income reported by and taxable to the unitholders. In addition to the potential settlement costs, the trustee has also incurred legal fees in representing the trust's interests in the ongoing arbitration. For unitholders, such costs will be reflected through an increase in the trust's administrative expenses, which are deductible by unitholders in determining the net royalty income from the trust.

Individuals may also incur expenses in connection with the acquisition or maintenance of trust units. These expenses, which are different from a unitholder's share of the trust's administrative expenses discussed above, may be deductible as "miscellaneous itemized deductions" only to the extent that such expenses exceed 2 percent of the individual's gross income.

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 Kansas, Oklahoma or Wyoming. Kansas and Oklahoma each impose a state income tax, which is potentially applicable to income from the net profits interests located in each of those states. 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 taxes the income of nonresidents from real property located within the state, and the trust has been advised by counsel that Oklahoma will tax nonresidents on income from the net profits interest located within the state. Kansas also taxes the income of nonresidents from property located within the state. However, for tax years beginning after December 31, 2012, Kansas allows individuals to deduct certain amounts, including net income from royalties reported on schedule E of their Form 1040 federal individual income tax return, from their federal adjusted gross income when calculating their Kansas taxable income. This deduction applies to amounts reported as royalty income that are received from grantor trusts, such as the trust. 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).

Wyoming does not have a state income tax.

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, 2012, the overhead charge was approximately $967,000 ($773,600 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 $22.3 million for 2012, or 34% of total gas sales, $35.6 million for 2011, or 35% of total gas sales and, $48.5 million for 2010, or 43% 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 were filed by the parties and ruled on by the court. XTO Energy has informed the trustee that after consideration of the rulings by the court in March and April of 2012, some benefiting XTO Energy and some benefiting the plaintiffs, and with due regard to the vagaries of litigation and their uncertain outcomes, XTO Energy and the plaintiffs entered into settlement negotiations prior to trial and reached a tentative settlement of $37 million on April 23, 2012. XTO has advised the trustee that $1.4 million of the settlement is attributable to Kansas claims which predate the Trust and therefore XTO Energy will not charge to the Trust. The settlement also includes a new royalty calculation for future royalty payments. The hearing for formal court approval was conducted on June 21, 2012 and preliminarily approved by the court on June 29, 2012. A fairness hearing was conducted on October 10, 2012 and the settlement was given final approval by the court. The court's order sets out the amount of attorneys' fees and costs awarded to the plaintiffs' counsel from the $37 million settlement. A third party administrator will make the distribution to the royalty owners as set out in the order approving the settlement.

XTO Energy has advised the trustee it believes that the terms of the conveyances covering the trust's net profits interests require the trust to bear its 80% interest in the settlement, or approximately $28.5 million, of which $23.4 million will affect the net proceeds from Oklahoma and $5.1 million will affect the net proceeds from Kansas. If so, this will adversely affect the net proceeds of the trust from Oklahoma and Kansas and will result in costs exceeding revenues on these properties. XTO Energy began deducting the settlement amount with the September 2012 distribution. Based on the revised settlement allocation between Oklahoma and Kansas and recent revenue and expense levels, the deductions XTO Energy has made, and will resume making if the Tribunal ultimately rules in XTO Energy's favor, will cause costs to exceed revenues for approximately 12 months on properties underlying the Oklahoma net profits interests and by approximately 7 years on properties underlying the Kansas net profits interests; however, changes in oil or natural gas prices or expenses could cause the time period to increase or decrease correspondingly. The net profits interest from Wyoming is unaffected and payments will continue to be made from those properties to the extent revenues exceed costs on such properties. XTO Energy has advised the trustee that the settlement would decrease the amount of net profits going forward for the Oklahoma and Kansas properties due to changes in the way costs (such as gathering, compression and fuel) associated with operating the properties will be allocated, resulting in a net gain to the royalty interest owners. XTO Energy has advised the trustee that this expected net upward revision for the royalty interest owners would reduce applicable net profits to XTO Energy and, correspondingly, to the trust. For 2012 the revision would have reduced trust net proceeds by approximately $272,000 (which amount would have been reflected in the June 2012 through December 2012 distributions).

The trustee has advised XTO Energy that all or a portion of the settlement amount should not be deducted from trust revenues. The trustee further advised XTO that, notwithstanding the Fankhouser settlement, XTO should make no change in the manner in which it calculates payments to the trust on a go-forward basis. XTO Energy does not agree with the trustee's position, and to resolve this disagreement XTO Energy initiated binding arbitration on August 1, 2012 in accordance with the terms of the dispute resolution provisions of the Trust Indenture. On August 17, 2012 the trustee filed its response to XTO's arbitration claim. All issues in the arbitration will be decided by a panel of three arbitrators (the "Tribunal"). Each side selected one arbitrator and the third arbitrator was selected by the other two appointed arbitrators. The arbitration will be administered by the American Arbitration Association under its commercial rules. The arbitration hearing is tentatively scheduled for October 7, 2013 in Fort Worth, Texas if not sooner disposed of by the parties by agreement or by the Tribunal on motion. Because XTO Energy advised the trustee that it began deducting the settlement in September, the trustee reserved a total of $900,000 from trust distributions to help fund potential legal and other expenses relating to the arbitration. The trustee believed that without such a reserve, the trust was likely to be left without adequate resources to fund the costs of the arbitration out of monthly trust revenues. Because the potential expenses of arbitration are uncertain, especially at this early stage of the arbitration, it is possible that the reserve may not be sufficient to cover all of such expenses.

The trustee requested that the Tribunal enjoin XTO Energy from continuing to deduct the Fankhouser settlement amount while the arbitration is pending. A hearing on the injunction was held on October 27, 2012. The Tribunal ordered that pending the issuance of a final award or further order of the Tribunal, XTO Energy should not treat any costs or expenses associated with the Fankhouser settlement as chargeable against the trust's net profit interest under the conveyances. The Tribunal denied the trust's request for an interim order directing XTO Energy to pay the trust the amounts offset against the trust's September and October 2012 distributions on the basis of the Fankhouser litigation. Based on this decision, deductions associated with the Fankhouser settlement were suspended starting in November 2012. XTO Energy has also informed the trustee that during the pendency of this action, no adjustment will be made to the net profits to the trust on a go-forward basis based on the changes in the way costs will be allocated to royalty owners in accordance with the Fankhouser settlement.

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. The case was certified as a class action in March 2012. XTO Energy has filed an appeal of the class certification to the 10th Circuit Court of Appeals on April 11, 2012, believing the class certification was not proper. The appeal was granted on June 26, 2012. The matter has been fully briefed, and oral argument is scheduled for May 8, 2013. The court will rule at a time of its discretion.

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*. The case was certified as a class action in April 2012. XTO Energy has filed an appeal of the class certification to the 10th Circuit Court of Appeals on April 26, 2012, believing the class certification was not proper. The appeal was granted on June 26, 2012. The matter has been fully briefed, and oral argument is scheduled for May 8, 2013. The court will rule at a time of its discretion.

XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to these lawsuits and intends to vigorously defend its position. However, XTO Energy is cognizant of other, similar litigation involving it, such as *Fankhouser*, and other, unrelated entities. As these cases develop XTO Energy will assess its legal position accordingly. If XTO Energy ultimately makes any settlement payments or receives a judgment against it in *Chieftain* or *Roderick*, XTO Energy has advised the trustee that it believes that the terms of the conveyances covering the trust's net profits interests require the trust to 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, XTO Energy has informed the trustee that the trust would bear its proportionate share of the increased payments through reduced net proceeds. In the event of any such settlement or judgment, the trustee intends to review any claimed reductions in payment to the trust based on the facts and circumstances of such settlement or judgment. 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, XTO Energy has advised the trustee that any reductions would result in costs exceeding revenues on the properties underlying the net profit interests of the cases named above, as applicable, for several monthly distributions, depending on the size of the judgment or settlement, if any, and the net proceeds being paid at that time, which would result in the net profits interest being limited until such time that the revenues exceed the costs for those net profit interests. If there is a settlement or judgment and should XTO Energy and the trustee disagree concerning the amount of the settlement or judgment to be charged against the trust's net profits interests, the matter will be resolved by binding arbitration under the terms of the Indenture creating the trust through the American Arbitration Association.

On September 12, 2012, a lawsuit was filed against Bank of America as trustee and XTO Energy styled *Harold Lamb v. Bank of America and XTO Energy Inc.,* in the U.S. District Court—Western District of Oklahoma. The plaintiff, Harold Lamb, is a unitholder in the trust and alleges that XTO Energy failed to properly pay and account to the trust under the terms of the net overriding royalty conveyance on certain Kansas and Oklahoma properties and that Bank of America, as trustee, failed to properly oversee such payment and accounting by XTO Energy. Additionally, the plaintiff alleges that Bank of America and XTO Energy have breached a fiduciary duty to the trust based on the allegations found in the *Fankhouser* class action discussed above. The plaintiffs are seeking unspecified amounts for actual/compensatory damages, punitive damages, disgorgement and injunctive relief. Subsequently, the plaintiff dismissed Bank of America from the lawsuit. The court granted XTO Energy's motion to transfer venue and has transferred the case to the U.S. District Court for the Northern District of Texas. XTO has also filed two motions to dismiss. XTO Energy has informed the trustee that it believes it has strong defenses to this lawsuit and intends to vigorously defend its position. However, XTO Energy is cognizant of other, similar litigation involving it, such as *Fankhouser*, and other, unrelated entities. As this case develops XTO Energy will assess its legal position accordingly.

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 the financial position or liquidity of the trust, but may have an effect on annual distributable income.

### *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, and year end costs for estimated future development and production expenditures to produce the proved reserves. 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 $3.21 per Mcf in 2012, $4.67 per Mcf in 2011, $4.45 per Mcf in 2010 and $3.28 per Mcf in 2009. Oil prices used to determine the standardized measure were based on average realized oil prices of $91.90 per Bbl in 2012, $92.92 per Bbl in 2011, $75.91 per Bbl in 2010 and $57.17 per Bbl in 2009.

***Proved Reserves***

| | Underlying Properties | | Net Profits Interests | |
|---|---|---|---|---|
| *(in thousands)* | Gas (Mcf) | Oil (Bbls) | Gas (Mcf) | Oil (Bbls) |
| 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 | 217 | 32 | 96 | 14 |
| Revisions of prior estimates | (21,574) | (29) | (43,010) | (350) |
| Production — sales volumes | (20,371) | (229) | (5,992) | (76) |
| Balance, December 31, 2012 | 248,181 | 2,513 | 77,356 | 875 |

Extensions, additions and discoveries in 2010, 2011 and 2012 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 2012 gas reserves related primarily to lower gas prices used to estimate reserves and 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, 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 |
| December 31, 2012 | 211,638 | 2,192 | 71,327 | 806 |

***Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves***

| (in thousands) | December 31 2012 | 2011 | 2010 |
|---|---|---|---|
| ***Underlying Properties*** | | | |
| Future cash inflows | $1,028,147 | $1,607,753 | $1,619,640 |
| Future costs: | | | |
| Production | 579,185 | 717,786 | 721,736 |
| Development | 64,064 | 67,668 | 68,201 |
| Future net cash flows | 384,898 | 822,299 | 829,703 |
| 10% discount factor | 181,595 | 403,608 | 405,114 |
| Standardized measure | $ 203,303 | $ 418,691 | $ 424,589 |
| ***Net Profits Interests*** | | | |
| Future cash inflows | $ 334,857 | $ 716,607 | $ 722,885 |
| Future production taxes | 26,939 | 58,767 | 59,122 |
| Future net cash flows | 307,918 | 657,840 | 663,763 |
| 10% discount factor | 145,275 | 322,887 | 324,092 |
| Standardized measure | $ 162,643 | $ 334,953 | $ 339,671 |

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

| (in thousands) | 2012 | 2011 | 2010 |
|---|---|---|---|
| ***Underlying Properties*** | | | |
| Standardized measure, January 1 | $ 418,691 | $424,589 | $275,029 |
| Revisions: | | | |
| Prices and costs | (215,934) | 40,475 | 207,026 |
| Quantity estimates | (2,787) | (9,059) | (1,121) |
| Accretion of discount | 36,486 | 37,013 | 23,818 |
| Future development costs | (1,734) | (3,504) | (796) |
| Production rates and other | (1,106) | (723) | (781) |
| Net revisions | (185,075) | 64,202 | 228,146 |
| Extensions, additions and discoveries | 1,102 | 606 | 18 |
| Production | (37,415) | (79,506) | (85,854) |
| Development costs | 6,000 | 8,800 | 7,250 |
| Net change | (215,388) | (5,898) | 149,560 |
| Standardized measure, December 31 | $ 203,303 | $418,691 | $424,589 |
| ***Net Profits Interests*** | | | |
| Standardized measure, January 1 | $ 334,953 | $339,671 | $220,023 |
| Extensions, additions and discoveries | 882 | 485 | 14 |
| Accretion of discount | 29,189 | 29,611 | 19,054 |
| Revisions of prior estimates, changes in price and other | (177,249) | 21,751 | 163,463 |
| Net profits income | (25,132) | (56,565) | (62,883) |
| Standardized measure, December 31 | $ 162,643 | $334,953 | $339,671 |

## 10. Quarterly Financial Data (Unaudited)

The following is a summary of net profits income, distributable income and distributable income per unit by quarter for 2012 and 2011:

| | Net Profits Income | Distributable Income | Distributable Income per Unit |
|---|---|---|---|
| **2012** | | | |
| **First Quarter** | **$10,073,319** | **$ 9,825,440** | **$0.245636** |
| **Second Quarter** | **6,956,529** | **6,561,840** | **0.164046** |
| **Third Quarter** | **3,131,255** | **2,149,320** | **0.053733** |
| **Fourth Quarter** | **4,970,935** | **4,736,320** | **0.118408** |
| | **$25,132,038** | **$23,272,920** | **$0.581823** |
| 2011 | | | |
| First Quarter | $13,214,098 | $12,940,000 | $0.323500 |
| Second Quarter | 14,667,930 | 14,402,760 | 0.360069 |
| Third Quarter | 15,477,314 | 15,333,360 | 0.383334 |
| Fourth Quarter | 13,206,026 | 13,088,840 | 0.327221 |
| | $56,565,368 | $55,764,960 | $1.394124 |

## Report of Independent Registered Public Accounting Firm

To the Unitholders of Hugoton Royalty Trust and
Bank of America, N.A., Trustee

We have audited the accompanying statements of assets, liabilities and trust corpus of Hugoton Royalty Trust (the "Trust") as of December 31, 2012 and 2011, and the related statements of distributable income and changes in trust corpus for each of the two years in the period ended December 31, 2012. We also have audited the Trust's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trustee is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the Trustee's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Trust's internal control over financial reporting based on our integrated 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 audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our 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, 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.

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

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the Trust at December 31, 2012 and 2011, and the distributable income and changes in trust corpus for each of the two years in the period ended December 31, 2012, on the basis of accounting described in Note 2. Also in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control — Integrated Framework* issued by COSO.

PricewaterhouseCoopers LLP

Dallas, Texas
March 8, 2013

## Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying statements of distributable income and changes in trust corpus of the Hugoton Royalty Trust for the year 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 audit.

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

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 results of distributable income and changes in trust corpus of Hugoton Royalty Trust for the year 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, 2012. The effectiveness of the trust's internal control over financial reporting as of December 31, 2012 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, 2012 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, 2012.

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 2010 through 2012 as specified in the trust indenture:

| Name and Principal Position | Year | Other Annual Compensation(1) |
|---|---|---|
| U.S. Trust, Bank of America | 2012 | $58,873 |
| Private Wealth Management, Trustee | 2011 | 51,936 |
| | 2010 | 52,563 |

(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 trustee is not aware of any person who beneficially owns more than 5% of the outstanding units.

(b) *Security Ownership of Management.* The trust has no directors or executive officers. As of January 25, 2013, Bank of America Corporation and its subsidiaries owned, in various fiduciary capacities, 1,016,894 units, with a shared right to vote 988,098 of these units and shared dispositive power with respect to 28,796 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, 2012 was approximately $967,000 per month, or $11,604,000 annually (net to the trust of $773,600 per month or $9,283,200 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 2010 through 2012 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, 2012 and 2011 are:

| | 2012 | 2011 |
|---|---|---|
| Audit fees-KPMG[(a)] | $10,017 | $ 59,350 |
| Audit fees-PwC | $89,900 | $ 50,000 |
| Audit-related fees | – | – |
| Tax fees | – | – |
| All other fees | – | – |
| | $99,917 | $109,350 |

(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)*

   Reports of Independent Registered Public Accounting Firm

   Statements of Assets, Liabilities and Trust Corpus at December 31, 2012 and 2011

   Statements of Distributable Income for the years ended December 31, 2012, 2011 and 2010

   Statements of Changes in Trust Corpus for the years ended December 31, 2012, 2011 and 2010

   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: March 8, 2013

By /s/ JAMES A. HALL
James A. Hall
Vice President — Upstream Business Services

(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, Trustee
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 LLP
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, 2012.

**Hugoton Royalty Trust**
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Private Wealth Management, Trustee
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