Hugoton

ROYALTY TRUST

2006

ANNUAL REPORT

Glossary of Terms

The following are definitions of significant terms used in this Annual Report:

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

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.

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 2006 and 2005:

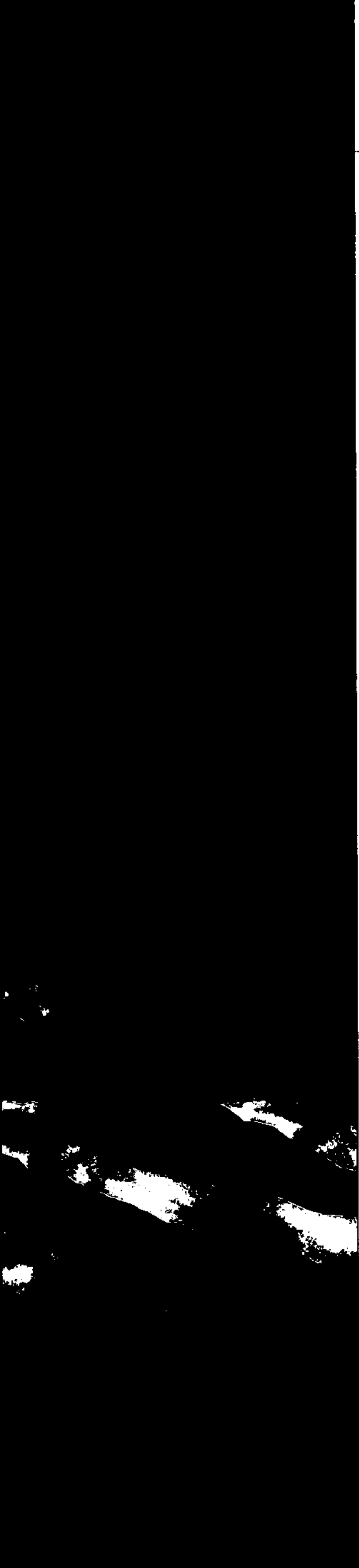
	SALES PRICE		
2006	**High**	**Low**	**Distributions per Unit**
First Quarter	$ 39.00	$ 29.27	$ 0.976040
Second Quarter	32.20	25.05	0.524306
Third Quarter	31.85	24.30	0.423020
Fourth Quarter	28.20	24.15	0.349403
TOTAL			**$ 2.272769**
2005			
First Quarter	$ 32.19	$ 23.72	$ 0.642454
Second Quarter	31.05	24.88	0.570801
Third Quarter	41.84	29.80	0.607605
Fourth Quarter	41.80	31.03	0.799937
TOTAL			**$ 2.620797**

At December 31, 2006, there were 40,000,000 units outstanding and approximately 1,254 unitholders of record; 39,101,894 of these units were held by depository institutions. 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.

In January 2006, XTO Energy announced that it would consider selling the underlying properties. However, XTO Energy advised the trustee in August 2006, that after a full review, it has decided to retain ownership of these underlying property interests at this time.

FORWARD-LOOKING STATEMENTS

This Annual Report, including the accompanying Form 10-K, includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this Annual Report and Form 10-K, including, without limitation, statements regarding estimates of proved reserves, future development plans and costs, and industry and market conditions, are forward-looking statements that are subject to a number of risks and uncertainties which are detailed in Part I, Item 1A of the accompanying Form 10-K. Although XTO Energy and the trustee believe that the expectations reflected in such forward-looking statements are reasonable, neither XTO Energy nor the trustee can give any assurance that such expectations will prove to be correct.



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 lower gas prices.

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. Unitholders should consult their tax advisors for further information.

As an example, a unitholder that acquired units in January 2006 and held them throughout 2006 would be entitled to a cost depletion deduction of approximately 5% of his cost. Assuming a cost of $38.00 per unit, cost depletion would offset approximately 79% of 2006 taxable trust income. Assuming a 30% tax rate, the 2006 taxable equivalent return as a percentage of unit cost would be 8%. (NOTE – Because the units are a depleting asset, a portion of this return is effectively a return of capital.)

To Unitholders

We are pleased to present the 2006 Annual Report of the Hugoton Royalty Trust. This report includes a copy of the trust's 2006 Form 10-K as filed with the Securities and Exchange Commission. Both reports contain important information about the trust's net profits interests, including information provided to the trustee by XTO Energy, and should be read in conjunction with each other.

For the year ended December 31, 2006, net profits income totaled $91,241,196. After adding interest income of $198,542 and deducting trust administration expense of $528,978, distributable income was $90,910,760 or $2.272769 per unit. Net profits income and distributions were 13% lower than 2005 amounts primarily because of higher development costs and production expense on the underlying properties.

Natural gas prices averaged $6.59 per Mcf for 2006, 1% lower than the 2005 average price of $6.64 per Mcf. The average 2006 oil price was $63.73 per Bbl, 22% higher than the 2005 average price of $52.27 per Bbl.

Gas sales volumes from the underlying properties for 2006 were 29,628,079 Mcf, or 81,173 Mcf per day, or a 1% decline from 82,155 Mcf per day in 2005. Oil sales volumes from the underlying properties were 332,525 Bbls, or 911 Bbls per day in 2006, or an increase of 2% from 891 Bbls per day in 2005. For further information on sales volumes and product prices, see "Trustee's Discussion and Analysis."

As of December 31, 2006, proved reserves for the underlying properties were estimated by independent engineers to be 420.5 Bcf of natural gas and 3.8 million Bbls of oil. Natural gas reserves for the underlying properties declined 22.6 Bcf primarily due to current year production and revisions related to lower year-end gas prices, partially offset by additions from development activity. Oil reserves for the underlying properties were relatively unchanged from year-end 2005 primarily because production was offset by reserve additions from development activity. Based on an allocation of these reserves, proved reserves attributable to the net profits interests were estimated to be 230.7 Bcf of natural gas and 2.2 million Bbls of oil. Estimated gas and oil reserves attributable to the net profits interests declined from previously reported reserves at year-end 2005, as current year production and revisions due to lower year-end prices were only partially offset by additions from development activities. All reserve information prepared by independent engineers has been provided to the trustee by XTO Energy.

Estimated future net cash flows from proved reserves of the net profits interests at December 31, 2006 are $1.3 billion. Using an annual discount factor of 10%, the present value of estimated future net cash flows at December 31, 2006 is $639 million. Proved reserve estimates and related future net cash flows have been determined based on a year-end average realized gas price of $5.60 per Mcf and a year-end West Texas Intermediate posted oil price of $57.75 per Bbl. Other guidelines used in estimating proved reserves, as prescribed by the Financial Accounting Standards Board, are described under Item 2 of the accompanying Form 10-K. The present value of estimated future net cash flows is not representative of the market value of trust units.

As disclosed in the tax instructions provided to unitholders in February 2007, trust distributions are considered portfolio income, rather than passive income. Unitholders should consult their tax advisors for further information.

Hugoton Royalty Trust
By: Bank of America, N.A., Trustee

Nancy G. Willis

By: Nancy G. Willis
Vice President

The Underlying Properties

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, 2006 is approximately 15 years. This index is calculated using total proved reserves and estimated 2007 production for the underlying properties. The projected 2007 production is from proved developed producing reserves as of December 31, 2006. Based on estimated future net cash flows at year-end oil and gas prices, the proved reserves of the underlying properties are approximately 91% natural gas and 9% oil. XTO Energy operates approximately 94% 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 – Years Ended December 31, 2006, 2005 and 2004 – Costs." Total 2006 development costs deducted for the underlying properties were $51.7 million, an increase of 32% from the prior year. XTO Energy has informed the trustee that total 2007 budgeted development costs for the underlying properties are approximately $46 million.

Hugoton Area

Discovered in 1922, the Hugoton area is one of the largest natural gas producing areas in the United States. During 2006, gas sales volumes from the underlying properties in the Hugoton area were 8.6 Bcf, or approximately 29% of total sales volumes from the underlying properties. Most of the production is from the Chase formation at depths of 2,700 to 2,900 feet. XTO Energy has informed the trustee that it plans to develop other formations, including the Council Grove, Chester, Morrow and St. Louis formations that underlie the 79,500 net acres held by production by the Chase formation wells. XTO Energy has participated in 3-D seismic shoots covering 30,000 acres of its net acreage position beneath the Chase formation.

Within this area, XTO Energy successfully drilled three gross (3.0 net) wells and performed 29 workovers in 2006, of which 20 were Chase restimulations. XTO Energy has informed the trustee that it plans to drill up to five wells and perform up to 30 workovers during 2007.

Anadarko Basin

The Anadarko Basin of western Oklahoma was discovered in 1945. Gas sales volumes from the underlying properties in the Anadarko Basin totaled 12.7 Bcf in 2006, or approximately 43% of total sales volumes from the underlying properties. 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.

In Major County, XTO Energy successfully drilled 12 gross (8.0 net) wells and performed 12 workovers in 2006. XTO Energy has informed the trustee that it plans to drill up to 12 wells and perform up to 15 workovers in Major County during 2007. In Woodward County, XTO Energy successfully drilled 12 gross (10.4 net) wells and performed five workovers in 2006. XTO Energy has informed the trustee that it plans to drill up to 11 wells and perform up to eight workovers in Woodward County during 2007.

In the Elk City field, XTO Energy successfully drilled two gross (1.8 net) wells and performed three workovers in 2006. XTO Energy has informed the trustee that it plans to drill up to four wells and perform up to six workovers within the Elk City field during 2007.

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 1970s. The producing reservoirs are the Cretaceous-aged Frontier, Baxter and Dakota sandstones at depths ranging from 7,500 to 10,000 feet. Gas sales volumes from the underlying properties in the Green River Basin were 8.3 Bcf in 2006, or approximately 28% of total sales volumes from the underlying properties.

In 2006, XTO Energy successfully drilled eight gross (8.0 net) wells and performed ten workovers. Of the eight wells drilled in 2006, two wells were completed and six wells were pending completion at December 31. XTO Energy has informed the trustee that it does not plan to perform any workovers or drill wells in the Green River Basin during 2007. XTO Energy is continuing its efforts to reduce pipeline pressure, which has shown potential for increasing production and extending field life in the Fontenelle Field.

Estimated Proved Reserves & 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, 2006:

	UNDERLYING PROPERTIES		NET PROFITS INTERESTS			
	PROVED RESERVES[a]		PROVED RESERVES[a][b]		FUTURE NET CASH FLOWS FROM PROVED RESERVES[a][c]	
(in thousands)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Undiscounted	Discounted
Oklahoma	264,571	3,603	151,772	2,075	$ 926,886	$ 455,237
Wyoming	124,772	149	63,732	76	313,194	149,243
Kansas	31,109	86	15,172	44	63,096	34,471
TOTAL	**420,452**	**3,838**	**230,676**	**2,195**	**$1,303,176**	**$ 638,951**

(a) Based on year-end oil and gas prices. For further information regarding trust proved reserves, see Item 2 of the accompanying Form 10-K.

(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.

Trustee's Discussion and Analysis

Years Ended December 31, 2006, 2005 and 2004

Net profits income for 2006 was $91,241,196, as compared with $105,129,321 for 2005 and $81,920,014 for 2004. The 13% decrease in net profits income from 2005 to 2006 is primarily the result of higher development costs and production expense. The 28% increase in net profits income from 2004 to 2005 was primarily the result of higher product prices, partially offset by increased development costs. Over 90% of net profits income in each year was attributable to natural gas sales.

Trust administration expense was $528,978 in 2006 as compared to $410,083 in 2005 and $357,891 in 2004. Increased administration expense from 2005 to 2006 is primarily because of higher unitholder reporting costs related to an increased number of unitholders. Increased administration expense from 2004 to 2005 was primarily because of increased fees related to the audit of the trust's internal control over financial reporting. Interest income was $198,542 in 2006, $112,642 in 2005 and $34,797 in 2004. Changes in interest income are attributable to fluctuations in net profits income and interest rates. Distributable income was $90,910,760 or $2.272769 per unit in 2006, $104,831,880 or $2.620797 per unit in 2005 and $81,596,920 or $2.039923 per unit in 2004.

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

Underlying gas sales volumes decreased 1% and underlying oil sales volumes increased 2% from 2005 to 2006 and from 2004 to 2005. Lower gas sales volumes over these periods were primarily because of natural production decline and the timing of cash receipts, which was largely offset by increased production from new wells and workovers. Oil sales volumes increased over these periods primarily because of increased production from new wells and workovers and the timing of cash receipts, partially offset by natural production decline.

Prices

Gas. The 2006 average gas price was $6.59 per Mcf, a 1% decrease from the 2005 average gas price of $6.64 per Mcf, which was 33% higher than the 2004 average gas price of $4.99 per Mcf. Since early 2004, gas prices have generally been increasing due primarily to increased demand and declining North American production. These trends accelerated in the second half of 2005 due to the effects of hurricanes on Gulf of Mexico production. During most of 2006, gas prices trended lower primarily because of an adequate natural gas supply inventory due to the warmer than normal weather during the winter of 2005-2006 and the absence of hurricane activity in the Gulf of Mexico in 2006. Much colder temperatures during February 2007 have caused prices to partially rebound. Prices will continue to be affected by weather, the U.S. economy, the level of North American production, crude oil prices and import levels of liquified natural gas. Natural gas prices are expected to remain volatile.

The trust's average gas price was $0.93, or 16%, lower than the average NYMEX price of $5.92 in 2004; $1.46, or 18%, lower than the average NYMEX price of $8.10 in 2005; and $1.43, or 18%, lower than the average NYMEX price of $8.02 in 2006. Because of the effects of the Gulf hurricanes, production from the underlying properties sold at a wider decrement to NYMEX prices in late 2005 and early 2006. The average NYMEX price for November 2006 through January 2007 was $7.10 per MMBtu. At February 15, 2007, the average NYMEX gas price for the following 12 months was $8.09 per MMBtu. Recent trust gas prices have averaged approximately 15% lower than the NYMEX price.

Oil. The average oil price for 2006 was $63.73 per Bbl, 22% higher than the average oil price for 2005 of $52.27 per Bbl, which was 37% higher than the 2004 average oil price of $38.11 per Bbl. Since early 2004, oil prices have generally been rising primarily because of increasing global demand and supply shortage concerns, inadequate sour crude refining capacity, reduced production as a result of tropical storms and hurricanes in the Gulf of Mexico in 2005 and political instability.

Rising tension in the Middle East caused oil prices to increase to record levels in July 2006, exceeding $78.00 per Bbl. Rising crude oil supplies, reduced geopolitical tension and the potential for lower demand in a slowing U.S. economy have caused recent oil prices to fluctuate between approximately $50.00 and $60.00 per Bbl. Oil prices are expected to remain volatile. The average NYMEX price for November 2006 through January 2007 was $58.68 per Bbl. At February 15, 2007, the average NYMEX oil price for the following 12 months was $60.56 per Bbl. Recent trust oil prices have averaged approximately 5% lower than the NYMEX price.

See "Gulf of Mexico Hurricanes" below.

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. There have been no excess costs or related recoveries since September 1999.

Taxes, transportation and other. Taxes, transportation and other generally fluctuates with changes in total revenues.

Production. Production expense increased 20% from 2005 to 2006 primarily because of increased repair and maintenance and insurance costs as a result of increased activity and higher industry costs and increased 3% from 2004 to 2005 primarily because of increased fuel costs.

Development. Development costs deducted were $51.7 million in 2006, $39.2 million in 2005 and $21.3 million in 2004. Increased development costs are primarily due to higher costs which are attributable to limited availability of drilling rigs, supplies and labor during a period of rising demand for these resources.

In 2006, underlying budgeted development costs deducted from distributions totaled $51.7 million, compared with actual development costs of $55.2 million. At December 31, 2006, cumulative actual costs exceeded cumulative budgeted costs deducted by approximately $3.4 million. Because of increased development activity and continued increasing costs, the monthly development cost deduction was increased twice in 2006. The deductions were increased to $4.2 million beginning with the April 2006 distribution and to $5.0 million beginning with the August 2006 distribution. With a reduction in development activity in first quarter 2007 and based on the development budget for 2007, the development cost deduction was lowered to $3.75 million beginning with the February 2007 distribution. 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 inflation adjustment.

Gulf of Mexico Hurricanes

In late August and September 2005, hurricanes in the Gulf of Mexico disrupted a significant portion of U.S. oil and gas production, leading to higher and more volatile commodity prices. These increased prices began affecting distributions to unitholders beginning with the November 2005 distribution that was paid in December 2005. The underlying properties to the trust are not located near the Gulf and related production was not significantly affected. However, because of greater supply and weaker demand in areas where trust-related oil and gas is produced, the price received for such production was significantly lower than NYMEX prices, which are generally representative of the price received for gas delivered in the Louisiana Gulf coast region. This effect on prices had substantially diminished by the April 2006 distribution that was paid in May 2006. Production expense and development costs also increased throughout the industry because of storm damages and related supply shortages.

Fourth Quarter 2006 and 2005

During fourth quarter 2006 the trust received net profits income totaling $14,067,286 compared with fourth quarter 2005 net profits income of $32,018,800. The 56% decrease in net profits income from fourth quarter 2005 to 2006 was primarily because of lower gas prices.

Administration expense was $127,815 and interest income was $36,649, resulting in fourth quarter 2006 distributable income of $13,976,120, or $0.349403 per unit. Distributable income for fourth quarter 2005 was $31,997,480 or $0.799937 per unit. Distributions to unitholders for the quarter ended December 31, 2006 were:

RECORD DATE	PAYMENT DATE	PER UNIT
Oct. 31, 2006	Nov. 14, 2006	$ 0.167660
Nov. 30, 2006	Dec. 14, 2006	0.136418
Dec. 29, 2006	Jan. 16, 2007	0.045325
TOTAL		**$ 0.349403**

The December 2006 distribution, paid in January 2007, was affected by significantly lower gas prices for October 2006 gas sales from the underlying properties.

Volumes

Fourth quarter underlying gas sales volumes decreased 1% and underlying oil sales volumes increased 12% from 2005 to 2006. Gas sales volumes decreased primarily because of natural production decline, which was largely offset by increased production from new wells and workovers. Increased oil sales volumes are primarily because of increased production from new wells and workovers and the timing of cash receipts, partially offset by natural production decline.

Prices

The average fourth quarter 2006 gas price was $5.28 per Mcf, or 36% lower than the fourth quarter 2005 average price of $8.24 per Mcf. The average fourth quarter 2006 oil price was $62.05 per Bbl, or 2% higher than the fourth quarter 2005 average price of $60.80 per Bbl. For further information about product prices, see "Years Ended December 31, 2006, 2005 and 2004 – Prices" on pages 6 and 7.

Costs

Taxes, transportation and other. Taxes, transportation and other generally fluctuates with changes in total revenues.

Production. Fourth quarter production expense increased 19% from 2005 to 2006 primarily because of increased repair and maintenance and insurance costs, partially offset by decreased fuel costs.

Overhead. Overhead increased 7% from fourth quarter 2005 to 2006 primarily because of the annual rate adjustment based on an oil and gas industry index.

For further information about costs, see "Years Ended December 31, 2006, 2005 and 2004 – Costs" on page 7.

See Item 7 of the accompanying Form 10-K for disclosures regarding liquidity and capital resources, off-balance sheet arrangements, contractual obligations and commitments, related party transactions and critical accounting policies of the trust. See Item 7A of the accompanying Form 10-K for quantitative and qualitative disclosures about market risk affecting the trust.

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]	
	2006	2005	2004	2006	2005
SALES VOLUMES					
Gas (Mcf)[b]					
Underlying properties	29,628,079	29,986,698	30,238,663	7,565,251	7,644,787
Average per day	81,173	82,155	82,619	82,231	83,096
Net profits interests	12,871,453	15,836,681	16,462,378	2,386,820	3,802,922
Oil (Bbls)[b]					
Underlying properties	332,525	325,193	318,694	89,214	79,788
Average per day	911	891	871	970	867
Net profits interests	145,230	177,980	184,487	28,686	46,056
AVERAGE SALES PRICES					
Gas (per Mcf)	$ 6.59	$ 6.64	$ 4.99	$ 5.28	$ 8.24
Oil (per Bbl)	$ 63.73	$ 52.27	$ 38.11	$ 62.05	$ 60.80
REVENUES					
Gas sales	$195,130,332	$198,985,047	$151,041,142	$ 39,960,899	$ 63,029,136
Oil sales	21,190,530	16,997,457	12,144,887	5,535,750	4,851,445
TOTAL REVENUES	**216,320,862**	**215,982,504**	**163,186,029**	**45,496,649**	**67,880,581**
COSTS					
Taxes, transportation and other	20,074,451	19,113,977	14,029,943	4,838,884	5,583,726
Production expense	22,231,559	18,468,101	17,893,352	5,932,299	4,979,279
Development costs[c]	51,700,000	39,200,000	21,300,000	15,000,000	15,300,000
Overhead	8,263,357	7,788,775	7,562,716	2,141,358	1,994,076
TOTAL COSTS	**102,269,367**	**84,570,853**	**60,786,011**	**27,912,541**	**27,857,081**
NET PROCEEDS	114,051,495	131,411,651	102,400,018	17,584,108	40,023,500
NET PROFITS PERCENTAGE	80%	80%	80%	80%	80%
NET PROFITS INCOME	**$ 91,241,196**	**$105,129,321**	**$ 81,920,014**	**$ 14,067,286**	**$ 32,018,800**

(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. Changes in any of these factors may result in disproportionate fluctuations in volumes allocated to the net profits interests. Therefore, comparative discussion of oil and gas sales volumes is based on the underlying properties.

(c) See Note 4 to Financial Statements.

Statements of Assets, Liabilities and Trust Corpus

	DECEMBER 31	
	2006	2005
Assets		
Cash and short-term investments	$ 1,813,000	$ 13,524,280
Net profits interests in oil and gas properties – net (Notes 1 and 2)	163,796,772	171,935,330
TOTAL	**$ 165,609,772**	**$ 185,459,610**
Liabilities and Trust Corpus		
Distribution payable to unitholders	$ 1,813,000	$ 13,524,280
Trust corpus (40,000,000 units of beneficial interest authorized and outstanding)	163,796,772	171,935,330
TOTAL	**$ 165,609,772**	**$ 185,459,610**

Statements of Distributable Income

	YEAR ENDED DECEMBER 31		
	2006	2005	2004
Net profits income	$ 91,241,196	$ 105,129,321	$ 81,920,014
Interest income	198,542	112,642	34,797
Total income	91,439,738	105,241,963	81,954,811
Administration expense	528,978	410,083	357,891
DISTRIBUTABLE INCOME	**$ 90,910,760**	**$ 104,831,880**	**$ 81,596,920**
DISTRIBUTABLE INCOME PER UNIT (40,000,000 UNITS)	**$ 2.272769**	**$ 2.620797**	**$ 2.039923**

Statements of Changes in Trust Corpus

	YEAR ENDED DECEMBER 31		
	2006	2005	2004
Trust corpus, beginning of year	$ 171,935,330	$ 182,551,814	$ 193,245,847
Amortization of net profits interests	(8,138,558)	(10,616,484)	(10,694,033)
Distributable income	90,910,760	104,831,880	81,596,920
Distributions declared	(90,910,760)	(104,831,880)	(81,596,920)
TRUST CORPUS, END OF YEAR	**$ 163,796,772**	**$ 171,935,330**	**$ 182,551,814**

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 6).

Bank of America, N.A. is the trustee for the trust. The trust indenture provides, among other provisions, that:

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

2. Basis of Accounting

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

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

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

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

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 $83,270,179 as of December 31, 2006 and $75,131,621 as of December 31, 2005.

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 6).

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.

4. 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:

	2006	2005	2004
Cumulative actual costs (over) under the amount deducted – beginning of period	$ 113,905	$ (319,927)	$ (1,583,988)
Actual costs	(55,224,079)	(38,766,168)	(20,035,939)
Budgeted costs deducted	51,700,000	39,200,000	21,300,000
Cumulative actual costs (over) under the amount deducted – end of period	**$ (3,410,174)**	**$ 113,905**	**$ (319,927)**

The monthly development deduction was increased twice during 2006 as a result of increased development activity and higher costs. The deductions were increased to $4.2 million beginning with the April 2006 distribution and to $5.0 million beginning with the August 2006 distribution. With a reduction in development activity in first quarter 2007 and based on the development budget for 2007, the development cost deduction was lowered to $3.75 million beginning with the February 2007 distribution. XTO Energy has advised the trustee that this monthly deduction will continue to be evaluated and revised as necessary.

5. Federal Income Taxes

Tax counsel has advised the trust that, under current tax laws, the trust will be classified as a grantor trust for federal income tax purposes and, therefore, is not subject to taxation at the trust level. However, the opinion of tax counsel is not binding on the Internal Revenue Service.

For federal income tax purposes, unitholders of a grantor trust 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 be received or accrued by the unitholders at the time such income is received or accrued by the trust, rather than when distributed by the trust.

6. XTO Energy Inc.

XTO Energy operates approximately 94% 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, 2006, the overhead charge was approximately $716,000 ($572,800 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.

In April and May 1999, XTO Energy sold 17 million trust units in the trust's initial public offering, and later in 1999 and 2000, sold 1.3 million trust units to certain of its officers. The trust did not receive any proceeds from the sale of trust units. 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. In January 2006, XTO Energy announced that it would consider selling the underlying properties. However, XTO Energy advised the trustee in August 2006, that after a full review, it has decided to retain ownership of these underlying property interests at this time.

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 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 $103.2 million for 2006, or 53% of total gas sales, $107.9 million for 2005, or 54% of total gas sales and $81.7 million for 2004, or 54% of total gas sales.

7. Contingencies

Litigation

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the United States District Court for the Western District of Oklahoma by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the U.S. False Claims Act against XTO Energy. The plaintiff alleges that XTO Energy underpaid royalties on natural gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% as a result of mismeasuring the volume of natural gas, incorrectly analyzing its heating content and improperly valuing the natural gas during at least the past ten years. The plaintiff seeks treble damages for the unpaid royalties (with interest, attorney's fees and expenses), civil penalties between $5,000 and $10,000 for each violation of the U.S. False Claims Act, and an order for XTO Energy to cease the allegedly improper measuring practices. This lawsuit against XTO Energy and similar lawsuits filed by Grynberg against more than 300 other companies have been consolidated in the United States District Court for Wyoming. In October 2002, the court granted a motion to dismiss Grynberg's royalty valuation claims, and Grynberg's appeal of this decision was dismissed for lack of appellate jurisdiction in May 2003. In response to a motion to dismiss filed by XTO Energy and other defendants in October 2006, the district judge held that Grynberg failed to establish the jurisdictional requirements to maintain the action against XTO Energy and other defendants and dismissed the actions for lack of subject matter jurisdiction. Grynberg has filed an appeal of this decision. While XTO Energy is unable to predict the final outcome of this case or estimate the amount of any possible loss, it has informed the trustee that it believes that the allegations of this lawsuit are without merit and intends to vigorously defend the action. However, an order to change measuring practices or a related settlement could adversely affect the trust by reducing net proceeds in the future by an amount that is presently not determinable, but, in XTO Energy management's opinion, is not currently expected to be material to the trust's annual distributable income, financial position or liquidity.

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 royalty owners of natural gas wells in Oklahoma. 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. A hearing on the class certification has not been scheduled. The plaintiffs have not stated an amount they are seeking. XTO Energy has informed the trustee that it believes that it has strong defenses to this lawsuit and intends to vigorously defend its position. However, if XTO Energy ultimately makes any settlement payments, the trust will bear its 80% share of such settlement related to production from the underlying properties. Additionally, if a judgment or settlement increases the amount of future payments to royalty owners, the trust would bear its proportionate share of the increased payments through reduced net proceeds. XTO Energy has informed the trustee that, although the amount of any reduction in net proceeds is not presently determinable, in its management's opinion, the amount is not currently expected to be material to the trust's annual distributable income, financial position or liquidity.

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

Other

Several states have enacted legislation to require state income tax withholding from nonresident recipients of oil and gas proceeds. After consultation with its state tax counsel, XTO Energy has advised the trustee that it believes the trust is not subject to these withholding requirements. However, regulations are subject to change by the various states, which could change this conclusion. Should the trust be required to withhold state taxes, distributions to the unitholders would be reduced by the required amount, subject to the unitholder's right to file a state tax return to claim any refund due.

8. Supplemental Oil and Gas Reserve Information (Unaudited)

Proved oil and gas reserve information is included in Item 2 of the trust's Annual Report on Form 10-K included in this report.

9. Quarterly Financial Data (Unaudited)

The following is a summary of net profits income, distributable income and distributable income per unit by quarter for 2006 and 2005:

2006	NET PROFITS INCOME	DISTRIBUTABLE INCOME	DISTRIBUTABLE INCOME PER UNIT
First Quarter	$ 39,085,394	$ 39,041,600	$ 0.976040
Second Quarter	21,125,072	20,972,240	0.524306
Third Quarter	16,962,944	16,920,800	0.423020
Fourth Quarter	14,067,286	13,976,120	0.349403
TOTAL	**$ 91,241,196**	**$ 90,910,760**	**$ 2.272769**
2005			
First Quarter	$ 25,818,940	$ 25,698,160	$ 0.642454
Second Quarter	22,965,660	22,832,040	0.570801
Third Quarter	24,325,921	24,304,200	0.607605
Fourth Quarter	32,018,800	31,997,480	0.799937
TOTAL	**$ 105,129,321**	**$ 104,831,880**	**$ 2.620797**

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 assets, liabilities and trust corpus of the Hugoton Royalty Trust as of December 31, 2006 and 2005, and the related statements of distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2006. These financial statements are the responsibility of the trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

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

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities, and trust corpus of the Hugoton Royalty Trust as of December 31, 2006 and 2005 and its distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2006 in conformity with the modified cash basis of accounting described in Note 2.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Hugoton Royalty Trust's internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2007 expressed an unqualified opinion on the trustee's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

KPMG LLP

Dallas, Texas
February 28, 2007

Report of Independent Registered Public Accounting Firm

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

We have audited the trustee's assessment, included in Trustee's Report on Internal Control over Financial Reporting under Item 9A of the accompanying Annual Report on Form 10-K, that the Hugoton Royalty Trust maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The trustee of the Hugoton Royalty Trust is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the trustee's assessment and an opinion on the effectiveness of the trust's internal control over financial reporting based on our audit.

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

The 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 the modified cash basis of accounting. The trust's internal control over financial reporting includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the modified cash basis of accounting, and that receipts and expenditures of the trust are being made only in accordance with authorizations of the trustee; and (3) 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 trustee's assessment that the Hugoton Royalty Trust maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control – Integrated Framework* issued by COSO. Also, in our opinion, the Hugoton Royalty Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities, and trust corpus of the Hugoton Royalty Trust as of December 31, 2006 and 2005, and the related statements of distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2006, and our report dated February 28, 2007 expressed an unqualified opinion on those financial statements and included an explanatory paragraph that described the trust's method of accounting as explained in Note 2 to the financial statements.

KPMG LLP

KPMG LLP

Dallas, Texas
February 28, 2007

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, 2006 **Commission file number 1-10476**

Hugoton Royalty Trust

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

SEC MAIL RECEIVED PROCESSING APR 20 2007 WASH. D.C. 186 SECTION

Texas (State or other jurisdiction of incorporation or organization)	**58-6379215** (I.R.S. Employer Identification No.)
Bank of America, N.A. **Trustee** **P.O. Box 830650** **Dallas, Texas** (Address of principal executive offices)	**75283-0650** (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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

The aggregate market value of the units of beneficial interest of the trust, based on the closing price on the New York Stock Exchange as of June 30, 2006 (the last business day of its most recently completed second fiscal quarter), held by non-affiliates of the registrant on that date was approximately $1.15 billion.

At February 28, 2007, 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:

2006 Annual Report to Unitholders - Part II

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. 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 any 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.

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.

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 Item 2., "Pricing and Sales Information."

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 91% of the net profits income received by the trust during 2006, as well as 91% of the estimated proved reserves of the net profits interests at December 31, 2006 (based on estimated future net cash flows using year-end oil and gas prices), 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.

Item 1A. *Risk Factors*

The following factors, among others, 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, among others, 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 in the trust's annual report to unitholders for the year ended December 31, 2006. 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 and natural gas, consumer demand, the price and availability of alternative fuels, the proximity to, and capacity of, transportation facilities and the effect of worldwide energy conservation measures. Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices in the long term. Lower oil and natural gas prices may reduce the amount of oil and natural gas that is economic to produce and will reduce net profits available to the trust. The volatility of energy prices reduces the predictability of future cash distributions to trust unitholders.

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

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

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

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

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 and 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. In addition, a reduction in depletion tax benefits may reduce the market value of the trust units.

The net proceeds payable to the trust are derived from the sale of depleting assets. Eventually, the properties underlying the trust's net profits interests will cease to produce in commercial quantities and the trust will, therefore, cease to receive any net proceeds therefrom. 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. The timing and size of these projects will depend on the market prices of oil and natural gas. If XTO Energy or other operators of the properties do not implement additional maintenance and successful development projects, the future rate of production decline of proved reserves may be higher than the rate currently estimated.

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 the 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 operators 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.

The trust indenture and related trust law permit the trustee and the trust to sue XTO Energy or any other operators 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 operators of the underlying properties.

Financial information of the trust is not prepared in accordance with 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 accounting principles generally accepted in the U.S., or 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 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 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 insure that such liabilities are to be satisfied only out of trust assets, under the laws of Texas, which are unsettled on this point, a 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, 2006, 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. 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. The underlying properties are predominantly natural gas producing leases located in the states of Kansas, Oklahoma and Wyoming. The principal productive areas are the Hugoton area, Anadarko Basin and Green River Basin.

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. In January 2006, XTO Energy announced that it would consider selling the underlying properties. However, XTO Energy advised the trustee in August 2006, that after a full review, it has decided to retain ownership of these underlying property interests at this time.

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 2006, daily sales volumes from the underlying properties in the Hugoton area averaged approximately 23,600 Mcf of gas and 74 Bbls of oil.

Most of the production from the underlying properties in the Hugoton area is from the Chase formation, at depths of 2,700 to 2,900 feet. XTO Energy has informed the trustee that it plans to develop other formations that underlie the 79,500 net acres held by production by the Chase formation wells, which range from 2,950 to 8,000 feet and 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 successful wells to these formations and plans to continue this development program in 2007. XTO Energy has participated in 3-D seismic shoots covering 30,000 acres of XTO Energy's net acreage position beneath the Chase formation.

Within this area, XTO Energy successfully drilled three gross (3.0 net) wells and performed 29 workovers in 2006, of which 20 were Chase restimulations. XTO Energy has informed the trustee that it plans to drill up to five wells and perform up to 30 workovers during 2007.

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 operated by a subsidiary. This system collects approximately 70% of its throughput from underlying properties, which, in recent months, has been approximately 16,950 Mcf per day from 264 wells. 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 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. This affiliate currently sells the residue to a pipeline at a price based on the monthly pipeline index less $0.01 per MMBtu.

Other Hugoton gas production is sold under a third party contract. Under the contract, XTO Energy receives 74.5% of the net proceeds received from the sale of the residue gas and liquids.

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 34,800 Mcf of gas and 799 Bbls of oil in 2006.

The fields in the Major County area are characterized by oil and gas production from a variety of structural and stratigraphic traps. Productive zones range from 6,500 to 9,400 feet and include the Oswego, Red Fork, Inola, Chester, Manning, Mississippian, Hunton and Arbuckle formations. Within this area, XTO Energy successfully drilled 12 gross (8.0 net) wells and performed 12 workovers in 2006. XTO Energy has informed the trustee that it plans to drill up to 12 wells and perform up to 15 workovers in Major County during 2007.

The fields within Woodward County are characterized primarily by gas production from a variety of structural and stratigraphic traps. Productive zones range from 6,000 to 7,500 feet and include the Cottage Grove, Oswego, Chester and Mississippian formations. Within this area, XTO Energy successfully drilled 12 gross (10.4 net) wells and performed five workovers in 2006. XTO Energy has informed the trustee that it plans to drill up to 11 wells and perform up to eight workovers in Woodward County during 2007.

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 range from 9,500 to 15,500 feet and include the Hoxbar, Atoka and Morrow formations. Within this area, XTO Energy successfully drilled two gross (1.8 net) wells and performed three workovers in 2006. XTO Energy has informed the trustee that it plans to drill up to four wells and perform up to six workovers within the Elk City field during 2007.

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 including life-of-production contracts. 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. 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 published index price. 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. During 2006, the gathering system collected approximately 13,500 Mcf per day from over 400 wells, approximately 52% of which XTO Energy operates. Estimated capacity of the gathering system is 28,000 Mcf per day. The gathering subsidiary also provides contract operating services to properties in Woodward County, collecting approximately 10,500 Mcf per day from 107 wells, for an average fee of approximately $0.10 per Mcf.

XTO Energy also sells gas directly to its marketing subsidiary, which then sells the gas to third parties. The price paid to XTO Energy is based upon the average price of several published indices, 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.

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 1970s. The producing reservoirs are the Cretaceous-aged Frontier, Baxter and Dakota sandstones at depths ranging from 7,500 to 10,000 feet.

Daily 2006 sales volumes from the underlying properties in the Fontenelle Field averaged 22,800 Mcf of natural gas and 38 Bbls of oil. In 2006, XTO Energy successfully drilled eight gross (8.0 net) wells and performed ten workovers. Of the eight wells drilled in 2006, two wells were completed and six wells were pending completion at December 31. XTO Energy has advised the trustee that it does not plan to perform any workovers or drill wells in the Green River Basin during 2007. XTO Energy 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 Unit and nearby properties under three different marketing arrangements. Under the agreement covering approximately 70% 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 35 miles to the gas plant, where the gas is processed, then redelivered to XTO Energy and sold to XTO Energy's marketing subsidiary. The owner of the gas plant and related pipeline charges XTO Energy for operational fuel and processing. In 2006, the fuel charge was 1.2% of the volumes produced and the processing fee was $0.10 per MMBtu. The marketing subsidiary then sells the residue gas to third parties based upon a spot sales price and pays the net sales proceeds to XTO Energy. The marketing subsidiary does not receive a marketing fee. The gas not sold under the above arrangement is sold either under a similar arrangement where the fee is $0.16 per MMBtu, or under a contract where XTO Energy directly sells the gas to a third party on the lease at an adjusted index price. Condensate is sold at the lease to an independent third party at market rates.

Producing Acreage 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 operated by XTO Energy and nonoperated wells are operated by other operators.

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, 2006. Undeveloped acreage is not significant.

	Gross	Net
Hugoton Area	216,790	199,590
Anadarko Basin	152,042	113,946
Green River Basin	39,155	26,899
Total	407,987	340,435

The following is a summary of the producing wells on the underlying properties as of December 31, 2006:

	Operated Wells		Nonoperated Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Gas	1,212	1,086.6	276	64.2	1,488	1,150.8
Oil	45	40.1	9	2.2	54	42.3
Total	1,257	1,126.7	285	66.4	1,542	1,193.1

The following is a summary of the number of wells drilled on the underlying properties during the years indicated. Unless otherwise indicated, all wells drilled are developmental. There were 13 gross (7.6 net) wells in process of drilling at December 31, 2006.

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Completed gas wells	44	28.8	41	29.2	25	19.2
Completed oil wells	3	0.6	1	1.0	—	—
Non-productive wells	1	0.1	1	0.5	4	1.5
Total *(a)*	48	29.5	43	30.7	29	20.7

(a) Included in totals are 17 gross (4.3 net) wells in 2006, 10 gross (2.4 net) wells in 2005 and 7 gross (1.1 net) wells in 2004, drilled on nonoperated 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 the three years ended December 31, 2006 were as follows:

	2006	2005	2004
Production			
Underlying Properties			
Gas—Sales (Mcf)	29,628,079	29,986,698	30,238,663
Average per day (Mcf)	81,173	82,155	82,619
Oil—Sales (Bbls)	332,525	325,193	318,694
Average per day (Bbls)	911	891	871
Net Profits Interests			
Gas—Sales (Mcf)	12,871,453	15,836,681	16,462,378
Average per day (Mcf)	35,264	43,388	44,979
Oil—Sales (Bbls)	145,230	177,980	184,487
Average per day (Bbls)	398	488	504
Average Sales Price			
Gas (per Mcf)	$ 6.59	$ 6.64	$ 4.99
Oil (per Bbl)	$63.73	$52.27	$38.11

Oil and Natural Gas Reserves

General

Miller and Lents, Ltd., independent petroleum engineers, has estimated oil and gas reserves attributable to the underlying properties as of December 31, 2006, 2005, 2004 and 2003. 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.

The standardized measure of discounted future net cash flows and changes in such discounted cash flows as presented below are prepared using assumptions required by the Financial Accounting Standards Board. These assumptions include the use of year-end prices for oil and gas and year-end costs for estimated future development and production expenditures to produce the proved reserves. Because natural gas prices are influenced by seasonal demand, use of year-end prices, as required by the Financial Accounting Standards Board, may not be the most representative in estimating future revenues or reserve data. 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.

Estimated costs to plug and abandon wells on the underlying 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 as described under Item 1.

Year-end weighted average realized gas prices used to determine the standardized measure were \$5.60 per Mcf in 2006, \$8.72 per Mcf in 2005, \$5.68 per Mcf in 2004 and \$5.76 per Mcf in 2003. Year-end oil prices used to determine the standardized measure were based on a West Texas Intermediate crude oil posted price of \$57.75 per Bbl in 2006, \$57.75 per Bbl in 2005, \$40.25 per Bbl in 2004 and \$29.25 per Bbl in 2003.

Proved Reserves

(in thousands)	Underlying Properties		Net Profits Interests	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
Balance, December 31, 2003	462,328	3,769	278,783	2,287
Extensions, additions and discoveries	16,905	228	9,676	131
Revisions of prior estimates	(5,061)	115	(17,404)	35
Production—sales volumes	(30,239)	(319)	(16,462)	(184)
Balance, December 31, 2004	443,933	3,793	254,593	2,269
Extensions, additions and discoveries	24,806	146	14,273	84
Revisions of prior estimates	4,292	167	18,902	258
Production—sales volumes	(29,987)	(325)	(15,837)	(178)
Balance, December 31, 2005	443,044	3,781	271,931	2,433
Extensions, additions and discoveries	17,853	203	8,938	102
Revisions of prior estimates	(10,817)	187	(37,322)	(195)
Production—sales volumes	(29,628)	(333)	(12,871)	(145)
Balance, December 31, 2006	420,452	3,838	230,676	2,195

Extensions, additions and discoveries in 2004, 2005 and 2006 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 year-end gas and oil prices. Higher upward and downward revisions for the net profits interests as compared with the underlying properties in each year were caused by changes in year-end 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

(in thousands)	Underlying Properties		Net Profits Interests	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
December 31, 2003	396,847	3,294	241,636	2,013
December 31, 2004	381,768	3,308	220,426	1,993
December 31, 2005	379,527	3,361	235,470	2,180
December 31, 2006	361,915	3,369	202,794	1,964

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)	December 31		
	2006	2005	2004
Underlying Properties			
Future cash inflows	$2,574,507	$4,092,655	$2,680,376
Future costs:			
Production	858,794	1,109,882	856,280
Development	86,744	80,610	57,059
Future net cash flows	1,628,969	2,902,163	1,767,037
10% discount factor	830,281	1,511,732	895,304
Standardized measure	$ 798,688	$1,390,431	$ 871,733
Net Profits Interests			
Future cash inflows	$1,420,936	$2,515,738	$1,539,521
Future production taxes	117,760	194,008	125,891
Future net cash flows	1,303,176	2,321,730	1,413,630
10% discount factor	664,225	1,209,385	716,244
Standardized measure	$ 638,951	$1,112,345	$ 697,386

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

(in thousands)

	2006	2005	2004
Underlying Properties			
Standardized measure, January 1	$1,390,431	$ 871,733	$ 925,812
Revisions:			
Prices and costs	(578,041)	566,014	(36,596)
Quantity estimates	5,912	5,744	(7,115)
Accretion of discount	119,526	75,570	79,856
Future development costs	(53,060)	(56,072)	(22,304)
Production rates and other	(944)	(92)	(176)
Net revisions	(506,607)	591,164	13,665
Extensions, additions and discoveries	28,915	58,946	34,656
Production	(165,751)	(170,612)	(123,700)
Development costs	51,700	39,200	21,300
Net change	(591,743)	518,698	(54,079)
Standardized measure, December 31	$ 798,688	$1,390,431	$ 871,733
Net Profits Interests			
Standardized measure, January 1	$1,112,345	$ 697,386	$ 740,650
Extensions, additions and discoveries	23,132	47,157	27,724
Accretion of discount	95,621	60,456	63,885
Revisions of prior estimates, changes in price and other *(a)*	(500,906)	412,475	(52;953)
Net profits income	(91,241)	(105,129)	(81,920)
Standardized measure, December 31	$ 638,951	$1,112,345	$ 697,386

(a) Revisions were primarily caused by the changes in year-end gas and oil prices and projected costs.

Regulation

Natural Gas Regulation

The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation rates charged, storage 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. 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. While natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. It is impossible to predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted, and what effect, if any, such proposals might have on the operations of the underlying properties.

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.

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.

State Income Tax Withholding

Several states have enacted legislation to require state income tax withholding from nonresident recipients of oil and gas proceeds. After consultation with its state tax counsel, XTO Energy has advised the trustee that it believes the trust is not subject to these withholding requirements. However, regulations are subject to change by the various states, which could change this conclusion. Should the trust be required to withhold state taxes, distributions to the unitholders would be reduced by the required amount, subject to the unitholder's right to file a state tax return to claim any refund due.

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.

Pricing and Sales Information

A subsidiary of XTO Energy purchases most of XTO Energy's natural gas production at a monthly published index price, then sells the gas to third parties for the best available price. The monthly published index price is generally the price established during the last five business days of the month preceding the month of delivery for the specific delivery location, which is based on the NYMEX price less the location differential during this period. Any marketing gains or losses are not included in trust net proceeds. 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. 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 2007. 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.

Item 3. ***Legal Proceedings***

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the United States District Court for the Western District of Oklahoma by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the U.S. False Claims Act against XTO Energy. The plaintiff alleges that XTO Energy underpaid royalties on natural gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% as a result of mismeasuring the volume of natural gas, incorrectly analyzing its heating content and improperly valuing the natural gas during at least the past ten years. The plaintiff seeks treble damages for the unpaid royalties (with interest, attorney's fees and expenses), civil penalties between $5,000 and $10,000 for each violation of the U.S. False Claims Act, and an order for XTO Energy to cease the allegedly improper measuring practices. This lawsuit against XTO Energy and similar lawsuits filed by Grynberg against more than 300 other companies have been consolidated in the United States District Court for Wyoming. In October 2002, the court granted a motion to dismiss Grynberg's royalty valuation claims, and Grynberg's appeal of this decision was dismissed for lack of appellate jurisdiction in May 2003. In response to a motion to dismiss filed by XTO Energy and other defendants in October 2006, the district judge held that Grynberg failed to establish the jurisdictional requirements to maintain the action against XTO Energy and other defendants and dismissed the actions for lack of subject matter jurisdiction. Grynberg has filed an appeal of this decision. While XTO Energy is unable to predict the final outcome of this case or estimate the amount of any possible loss, it has informed the trustee that it believes that the allegations of this lawsuit are without merit and intends to vigorously defend the action. However, an order to change measuring practices or a related settlement could adversely affect the trust by reducing net proceeds in the future by an amount that is presently not determinable, but, in XTO Energy management's opinion, is not currently expected to be material to the trust's annual distributable income, financial position or liquidity.

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 royalty owners of natural gas wells in Oklahoma. 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. A hearing on the class certification has not been scheduled. The plaintiffs have not stated an amount they are seeking. XTO Energy has informed the trustee that it believes that it has strong defenses to this lawsuit and intends to vigorously defend its position. However, if XTO Energy ultimately makes any settlement payments, the trust will bear its 80% share of such settlement related to production from the underlying properties. Additionally, if a judgment or settlement increases the amount of future payments to royalty owners, the trust would bear its proportionate share of the increased payments through reduced net proceeds. XTO Energy has informed the trustee that, although the amount of any reduction in net proceeds is not presently determinable, in its management's opinion, the amount is not currently expected to be material to the trust's annual distributable income, financial position or liquidity.

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

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

No matters were submitted to a vote of unitholders during 2006.

PART II

Item 5. ***Market for Units of the Trust, Related Security Holder Matters and Trust Purchases of Units***

The section entitled "Units of Beneficial Interest" on page 1 of the trust's annual report to unitholders for the year ended December 31, 2006 is incorporated herein by reference.

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				
	2006	2005	2004	2003	2002
Net Profits Income	$ 91,241,196	$105,129,321	$ 81,920,014	$ 80,687,778	$ 29,934,195
Distributable Income	90,910,760	104,831,880	81,596,920	80,373,120	29,572,360
Distributable Income per Unit ..	2.272769	2.620797	2.039923	2.009328	0.739309
Distributions per Unit	2.272769	2.620797	2.039923	2.009328	0.739309
Total Assets at Year-End.......	165,609,772	185,459,610	189,499,334	198,952,087	208,721,083

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

The "Trustee's Discussion and Analysis" of financial condition and results of operations for the three-year period ended December 31, 2006 on pages 6 through 9 of the trust's annual report to unitholders for the year ended December 31, 2006 is incorporated herein by reference.

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 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.

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, 2006, other than the December distribution payable to unitholders in January 2007, 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...	$1,813,000	$1,813,000	$—	$—	$—

Related Party Transactions

The underlying properties from which the net profits interests were carved are currently owned by XTO Energy, which operates approximately 94% 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, 2006, the monthly overhead charge, based on the number of operated wells, was approximately $716,000 ($572,800 net to the trust) and is subject to annual adjustment based on an oil and gas industry index.

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. In January 2006, XTO Energy announced that it would consider selling the underlying properties. However, XTO Energy advised the trustee in August 2006, that after a full review, it has decided to retain ownership of these underlying property interests at this time.

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 Item 2, Properties, and Note 6 to Financial Statements in the trust's annual report to unitholders for the year ended December 31, 2006. Total gas sales from the underlying properties to XTO Energy's wholly owned subsidiaries were $103.2 million for 2006, or 53% of total gas sales, $107.9 million for 2005, or 54% of total gas sales and $81.7 million for 2004, or 54% of total gas sales.

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 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 in the trust's annual report to unitholders for the year ended December 31, 2006.

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 prices at the date of the evaluation, 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 Item 2, is prepared using assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission. Such assumptions include using year-end oil and gas prices 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, development activities, future development plans, increased density drilling, maintenance projects, development, production and other costs, oil and gas prices, pricing differentials, proved reserves, 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.

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 the trust's 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***

The financial statements of the trust and the notes thereto, together with the related reports of KPMG LLP dated February 28, 2007, appearing on pages 10 through 16 of the trust's annual report to unitholders for the year ended December 31, 2006, are incorporated herein by reference.

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

There have been no changes in accountants and no disagreements with the trust's independent registered public accountants on any matter of accounting principles or practices or financial statement disclosures during the two years ended December 31, 2006.

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., 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, 2006. The trustee's assessment of the effectiveness of the trust's internal control over financial reporting as of December 31, 2006 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report on page 16 of the trust's annual report to unitholders for the year ended December 31, 2006 which is incorporated herein by reference.

There were no changes in the trust's internal control over financial reporting during the quarter ended December 31, 2006 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 and Executive Officers of the Registrant***

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 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. The Securities and Exchange Commission has taken the position that executive officers and directors of XTO Energy must also file initial ownership reports and reports of changes in beneficial ownership. Copies of the reports must be provided to the trust. To the trustee's knowledge, based solely on the information furnished to the trust, the trust 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, 2006, with the exception of one late filing related to one transaction by an immediate family member of Mr. Jack P. Randall, a director of XTO Energy. This transaction has now been reported.

Because the trust has no employees, it does not have a code of ethics. Employees of the trustee, Bank of America, N.A., 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 2004 through 2006 as specified in the trust indenture:

Name and Principal Position	Year	Other Annual Compensation (1)
Bank of America, N.A., Trustee	2006	$47,410
	2005	35,000
	2004	35,000

(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***

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 February 22, 2007, Bank of America, N.A. owned, in various fiduciary capacities, 99,610 units, with a shared right to vote 17,156 of these units and no right to vote 82,454 of these units. Bank of America, N.A. disclaims any beneficial interests in these units. The number of units reflected in this paragraph includes units held by all branches of Bank of America, N.A.

(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*

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, 2006 was approximately $716,000 per month, or $8,592,000 annually (net to the trust of $572,800 per month or $6,873,600 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 "Hugoton Area," "Anadarko Basin," "Green River Basin" and "Pricing and Sales Information," of Item 2.

See Item 11 for the remuneration received by the trustee from 2004 through 2006 and Item 12(b) for information concerning units owned by the trustee, Bank of America, N.A., in various fiduciary capacities.

Item 14. *Principal Accounting Fees and Services*

Fees for services performed by KPMG LLP for the years ended December 31, 2006 and 2005:

	2006	2005
Audit fees	$71,750	$66,000
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
	$71,750	$66,000

As referenced in Item 10, above, the trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to 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 (incorporated by reference in Item 8 of this report)*

   Independent Registered Public Accounting Firm Reports
   Statements of Assets, Liabilities and Trust Corpus at December 31, 2006 and 2005
   Statements of Distributable Income for the years ended December 31, 2006, 2005 and 2004
   Statements of Changes in Trust Corpus for the years ended December 31, 2006, 2005 and 2004
   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.

(13) Hugoton Royalty Trust annual report to unitholders for the year ended December 31, 2006

(23.1) Consent of KPMG LLP

(23.2) Consent of Miller and Lents, Ltd.

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

(32) Section 1350 Certification

Copies of the above Exhibits are available to any unitholder, at the actual cost of reproduction, upon written request to the trustee, Bank of America, N.A., 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

XTO ENERGY INC.

Date: March 1, 2007

By /s/ LOUIS G. BALDWIN
Louis G. Baldwin
Executive Vice President and
Chief Financial Officer

(The trust has no directors or executive officers.)

HUGOTON ROYALTY TRUST
901 Main Street, 17th Floor
P.O. Box 830650
Dallas, Texas 75283-0650
877.228.5083
Bank of America, N.A., Trustee

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.

WEB SITE
www.hugotontrust.com

AUDITORS
KPMG LLP
Dallas, Texas

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

TAX COUNSEL
Winstead Sechrest & Minick P.C.
Houston, Texas

TRANSFER AGENT AND REGISTRAR
Mellon Investor Services, L.L.C.
www.melloninvestor.com

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