Hugoton
ROYALTY TRUST

ANNUAL REPORT

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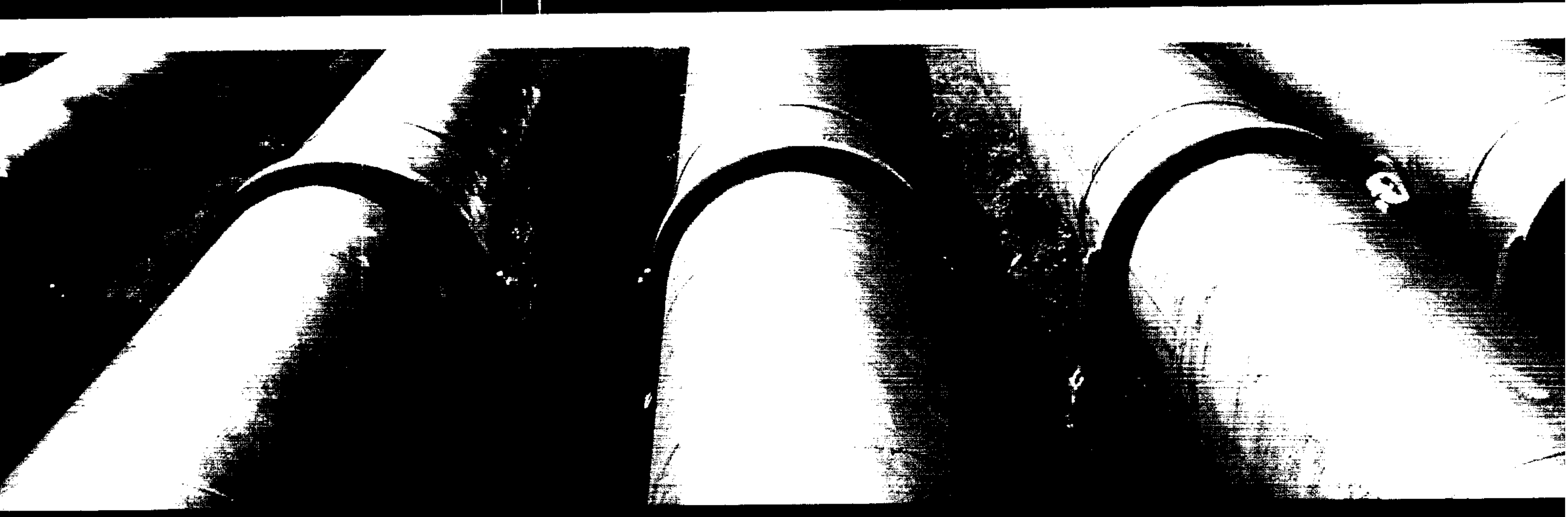

Glossary of Terms

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 that are working interests in Kansas, Oklahoma and Wyoming.

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 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 2002 and 2001:

	Sales Price		
2002	**High**	**Low**	**Distributions/Unit**
First Quarter	$12.10	$ 9.44	$0.183816
Second Quarter	12.43	10.22	0.133366
Third Quarter	12.00	9.44	0.215567
Fourth Quarter	13.19	10.86	0.206560
Total			**$0.739309**
2001			
First Quarter	$16.00	$13.50	$0.841362
Second Quarter	17.01	12.00	0.543291
Third Quarter	13.70	9.70	0.381796
Fourth Quarter	11.67	9.91	0.211827
Total			**$1.978276**

At December 31, 2002, there were 40,000,000 units outstanding and approximately 154 unitholders of record; 17,694,639 of these units were held by depository institutions. As of March 3, 2003, XTO Energy owned 21,705,893 units.

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 II, Item 7 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 costs, 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.

Unitholders may be eligible to receive the following tax benefits, but should consult their tax advisors:

- **The Nonconventional Fuel Source Tax Credit** is related to tight sands gas production sold through 2002 from wells drilled on the underlying properties prior to January 1, 1993, and after November 5, 1990, or after December 31, 1979 if the related formation was dedicated to interstate commerce as of April 20, 1977. This tax credit may be used to reduce the unitholder's regular income tax liability, but not below his tentative minimum tax. Congress has considered extending this credit beyond the December 31, 2002 expiration date, and the creation of similar new tax credits. Unless new legislation is passed, extending this credit on existing eligible production or allowing for credits on new production, there will be no further benefit on production past the year 2002.

- **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 2002 and held them throughout 2002 would be entitled to a cost depletion deduction of approximately 5% of his cost. Assuming a cost of $10.00 per unit, cost depletion would offset 63% of 2002 taxable trust income. After considering the tight sands tax credit and assuming a 30% tax rate, the 2002 taxable equivalent return as a percentage of unit cost would be 9%. (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 2002 Annual Report of the Hugoton Royalty Trust. This report includes a copy of the trust's 2002 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, 2002, net profits income totaled $29,934,195. After adding interest income of $14,955 and deducting trust administration expense of $376,790, distributable income was $29,572,360 or $0.739309 per unit. Net profits income and distributions were 62% lower than 2001 amounts primarily because of lower average gas prices.

Natural gas prices averaged $2.44 per Mcf for 2002, 43% lower than the 2001 average price of $4.30 per Mcf. The average 2002 oil price was $23.70 per Bbl, 14% lower than the 2001 average price of $27.60 per Bbl.

Gas sales volumes from the underlying properties for 2002 were 34,315,145 Mcf, or 94,014 Mcf per day, or a 6% decline from 100,268 Mcf per day in 2001. Oil sales volumes from the underlying properties were 353,185 Bbls, or 968 Bbls per day in 2002, or a decline of 10% from 1,079 Bbls per day in 2001. For further information on sales volumes and product prices, see "Trustee's Discussion and Analysis."

Tight sands gas sales volumes from the underlying properties were 2,058,927 Mcf in 2002. After reduction of volumes related to production and development costs, tight sands gas sales volumes allocated to the net profits interests were 212,008 Mcf, resulting in a tight sands tax credit for the year of $0.002991 per unit. This credit (or a portion thereof, if units were acquired after January 2002) can be applied against the unitholder's regular federal income tax liability, subject to certain limitations. Unitholders should consult their tax advisors regarding use of this credit.

As of December 31, 2002, proved reserves for the net profits interests were estimated by independent engineers to be 299.2 Bcf of natural gas and 2.6 million Bbls of oil. Estimated gas reserves increased 16% and oil reserves increased 24% from year-end 2001 to 2002, primarily because of the increase in year-end realized gas prices from $2.34 to $4.37 per Mcf and West Texas Intermediate posted oil prices from $16.75 to $28.00 per Bbl and the resulting increased allocation of reserves to the net profits interests. 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, 2002 are $1.26 billion, or $31.39 per unit. Using an annual discount factor of 10%, the present value of estimated future net cash flows at December 31, 2002 is $609.5 million, or $15.24 per unit. Proved reserve estimates and related future net cash flows have been determined based on year-end oil and gas prices, as well as other guidelines prescribed by the Financial Accounting Standards Board as further 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 discussed in the tax instructions provided to unitholders in February 2003, 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
Assistant 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, 2002 is approximately 15 years. This index is calculated using total proved reserves and estimated 2003 production for the underlying properties. Based on estimated future net cash flows at year-end oil and gas prices, the proved reserves of the underlying properties are approximately 94% natural gas and 6% oil. XTO Energy operates approximately 94% of the underlying properties.

Because the underlying properties are working interests, production and development costs 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, 2002, 2001 and 2000 – Costs." Total 2002 development costs for the underlying properties were $22,733,333, a decrease of 25% from the prior year. XTO Energy has informed the trustee that total 2003 budgeted development costs for the underlying properties are $16 million.

Hugoton Area

Discovered in 1922, the Hugoton area is the largest natural gas producing area in North America. During 2002, gas sales volumes from the Hugoton area were 10,414,000 Mcf, or approximately 30% 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.

During 2002, development of the Hugoton area included four successful recompletions to the Towanda formation. XTO Energy also continued its restimulation program in the Chase intervals, completing 33 of these restimulations in 2002. XTO Energy has informed the trustee that it plans to perform 35 Chase restimulations during 2003.

Anadarko Basin

The Anadarko Basin of western Oklahoma was discovered in 1945. Gas sales volumes from the Anadarko Basin totaled 15,369,000 Mcf in 2002, or approximately 45% 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 in Major County, the principal producing region of the underlying properties in the Anadarko Basin.

In Major and Woodward counties, the Mississippian (Osage), Chester and Red Fork formations were the primary drilling targets in 2002. In Major County, XTO Energy successfully drilled seven gross (4.9 net) wells. XTO Energy has informed the trustee that it plans to drill up to six wells and perform up to 11 workovers in Major County in 2003. In Woodward County, the Chester formation, with its four separate producing intervals, was the primary target for ten gross (8.0 net) wells successfully drilled and completed during 2002. XTO Energy has informed the trustee that it plans to drill up to 12 gross (11.5 net) wells and perform up to five workovers in Woodward County during 2003.

Estimated Proved Reserves & Future Net Cash Flows

The following are proved reserves of the underlying properties and proved reserves and future net cash flows from proved reserves of the net profits interests at December 31, 2002, as estimated by independent engineers:

	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	286,574	3,829	181,806	2,427	$ 822,283	$416,867
Wyoming	148,161	213	93,061	134	352,995	150,314
Kansas	41,766	69	24,330	40	80,696	42,328
Total	**476,501**	**4,111**	**299,197**	**2,601**	**$1,255,974**	**$609,509**

(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.

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 Cretacious-aged Frontier and Dakota sandstones at depths ranging from 7,500 to 10,000 feet. Gas sales volumes from the Green River Basin were 8,532,000 Mcf in 2002, or approximately 25% of total sales volumes from the underlying properties.

XTO Energy has informed the trustee that its development activities in the Fontenelle Field were delayed for the better part of 2002 due to the pipeline limitations and price volatility. XTO Energy plans to perform up to five workovers and may drill up to five wells in the Green River Basin during 2003.

Trustee's Discussion & Analysis

Years Ended December 31, 2002, 2001 and 2000

Net profits income for 2002 was $29,934,195, as compared with $79,272,395 for 2001 and $56,812,141 for 2000. The 62% decrease in net profits income from 2001 to 2002 was caused by lower average gas prices in 2002, while the 40% increase in net profits income from 2000 to 2001 was caused by higher average gas prices in 2001. Approximately 91% in 2002, 94% in 2001 and 90% in 2000 of net profits income was derived from natural gas sales.

Trust administration expense was $376,790 in 2002 as compared to $277,532 in 2001 and $228,211 in 2000. Increased administration expense from 2001 to 2002 is primarily related to increased stock exchange listing fees. Increased administration expense from 2000 to 2001 is primarily related to increased unitholder reporting costs. Interest income was $14,955 in 2002, $136,177 in 2001 and $128,150 in 2000. Changes in interest income are attributable to fluctuations in net profits income and interest rates. Distributable income was $29,572,360 or $0.739309 per unit in 2002, $79,131,040 or $1.978276 per unit in 2001 and $56,712,080 or $1.417802 per unit in 2000.

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

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

Volumes

From 2001 to 2002, underlying gas sales volumes decreased 6% and underlying oil sales volumes decreased 10% primarily because natural production decline exceeded the effects of new wells and workovers. From 2000 to 2001, underlying gas sales volumes decreased 1% and underlying oil sales volumes decreased 2% primarily because natural production decline slightly exceeded the effects of new wells and workovers.

Underlying tight sands gas sales volumes decreased 2% from 2,104,845 Mcf in 2001 to 2,058,927 Mcf in 2002. After reduction of volumes related to production and development costs, tight sands gas volumes allocated to the net profits interests in 2002 were 212,008 Mcf, which were significantly lower than volumes of 1,230,270 Mcf allocated to the net profits interests in 2001. This decrease in tight sands gas sales volumes allocated to the net profits interests was because of higher development costs on the related underlying properties in 2002, which resulted in a similar decrease in the tight sands credit per unit.

Prices

Gas. The 2002 average gas price was $2.44 per Mcf, a 43% decrease from the 2001 average gas price of $4.30 per Mcf, which was a 37% increase from the 2000 average gas price of $3.14 per Mcf. At the beginning of 2000, NYMEX gas prices approximated $2.30 per MMBtu. Gas prices strengthened in 2000, reaching a record high of $10.10 per MMBtu in December 2000 as winter demand strained gas supplies. Prices subsequently declined during 2001 because of fuel switching due to higher prices, milder weather and a weaker economy, which reduced demand for gas to generate electricity. The December 31, 2001 NYMEX gas price was $2.57 per MMBtu. Despite the winter of 2001-2002 being one of the warmest on record and higher than average gas storage levels, gas prices gradually climbed in 2002 as a result of low levels of drilling activity, increased industrial demand, colder weather late in 2002 and international instability. With colder than normal weather and seasonally low gas storage levels, gas prices have continued to rise in 2003. The average NYMEX price for January and February 2003 was $5.97 per MMBtu. Gas prices have risen in March 2003 to an average NYMEX price of $6.49 through March 14.

The trust's average gas price for January 2003 gas sales was approximately $1.00 per MMBtu lower than the average NYMEX price, primarily because of lower Wyoming prices related to pipeline constraints and reduced West Coast demand. In early March 2003, the Wyoming index price was approximately $4.00 lower than the NYMEX price of $9.00, which was elevated because gas supplies to the northeast U.S. were strained from severe winter weather. The gas price differential in Wyoming is expected to narrow later in 2003 because of pipeline expansion projects aimed at increasing capacity to western markets. These projects are anticipated to ultimately lead to higher gas prices for the region's producers.

Oil. The average oil price for 2002 was $23.70 per Bbl, 14% lower than the 2001 average oil price of $27.60 per Bbl, which was 4% lower than the 2000 average price of $28.67 per Bbl. Despite OPEC production increases in 2000, increased demand sustained higher prices. The West Texas Intermediate ("WTI") posted price reached $34.25 in September 2000, then its highest level in ten years. Lagging demand, resulting from a worldwide economic slowdown, caused oil prices to decline during 2001. OPEC members agreed to cut daily production by one million barrels in April 2001 and an additional one million barrels in September 2001 to adjust for weak demand and excess supply. The economic decline was accelerated by the terrorist attacks in the U.S. on September 11, 2001, placing additional downward pressure on oil prices. OPEC cut an additional 1.5 million barrels per day during 2002. Oil prices increased during 2002 largely because of OPEC production discipline and rising uncertainty surrounding the Middle East. OPEC members agreed to increase daily oil production 1.5 million barrels beginning February 1, 2003, to help stabilize a volatile world market. However, with the war in Iraq, oil prices are expected to remain volatile. The average WTI posted price for January and February 2003 was $30.95. Oil prices have risen in March 2003 to an average WTI posted price of about $33.63 through March 14. Recent trust oil prices have averaged approximately $2.60 higher than the WTI posted price.

Costs

The calculation of net profits income includes deductions for production and 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 expenses increased 3% from 2001 to 2002 because of increased compressor fuel, maintenance, insurance and labor costs and saltwater disposal expense. Production expenses increased 11% from 2000 to 2001 because of the timing of maintenance projects and higher compressor rentals.

Development. Development costs were $22.7 million in 2002, $30.4 million in 2001 and $22.8 million in 2000. The decrease from 2001 to 2002 is attributable to fewer wells drilled and workovers in Oklahoma. Development costs for 2001 were higher because of increased drilling, service and equipment costs related to demand generated by higher natural gas prices, as well as carryover of costs from 2000.

In 2002, budgeted development costs deducted from distributions totaled $22.7 million, compared with actual development costs of $14.9 million. At December 31, 2002, cumulative development costs deducted exceeded actual costs by $3.1 million. This excess is expected to be reduced as 2002 development costs are billed and paid in 2003. Based on the 2003 budget, XTO Energy decreased the monthly development cost deduction from $1.9 million to $1 million beginning with the February 2003 distribution.

Overhead. Overhead is charged by XTO Energy for reimbursement of administrative expenses of operating 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.

Other Proceeds

Net profits income for 2002 includes proceeds of $60,000 ($48,000 net to the trust) from the sale of an underlying property in Major County, Oklahoma. Net profits income for 2001 includes proceeds of $307,824 ($246,259 net to the trust) from the sale of certain underlying properties in Sweetwater County, Wyoming.

Fourth Quarter 2002 and 2001

During fourth quarter 2002 the trust received net profits income totaling $8,290,621, compared with fourth quarter 2001 net profits income of $8,507,804. The 3% decrease in net profits income from fourth quarter 2001 to 2002 was primarily because of lower product volumes partially offset by higher product prices.

Administration expense was $31,879 and interest income was $3,658, resulting in fourth quarter 2002 distributable income of $8,262,400, or $0.206560 per unit. Distributable income for fourth quarter 2001 was $8,473,080 or $0.211827 per unit. Distributions to unitholders for the quarter ended December 31, 2002 were:

Record Date	Payment Date	Per Unit
Oct. 31, 2002	Nov. 15, 2002	$0.062028
Nov. 29, 2002	Dec. 13, 2002	0.063836
Dec. 31, 2002	Jan. 15, 2003	0.080696
Total		$0.206560

Volumes

Fourth quarter underlying gas sales volumes decreased 12% while underlying oil sales volumes declined 13%. The decrease in oil and gas sales volumes is primarily because of natural production decline and timing of cash receipts.

Prices

The average fourth quarter 2002 gas price was $2.52 per Mcf, or 15% higher than the fourth quarter 2001 average price of $2.19. The average fourth quarter oil price was $28.16 per Bbl, or 13% higher than the fourth quarter 2001 average price of $25.02. For further information about product prices, see "Years Ended December 31, 2002, 2001 and 2000 – Prices" above.

Costs

Production. Fourth quarter production expenses increased 39% from 2001 to 2002 because of prior period salt water disposal adjustments recorded in fourth quarter 2001, and increased insurance premiums and the timing of maintenance projects and disbursements in fourth quarter 2002.

Development. Development costs, which were deducted based on budgeted development costs, declined 2% from fourth quarter 2001 to 2002.

Overhead. Overhead decreased 33% from fourth quarter 2001 to 2002 because of the timing of an annual Oklahoma administrative fee and a one-time reduction of prior period overhead on certain Wyoming wells.

For further information about costs, see "Years Ended December 31, 2002, 2001 and 2000 – Costs" above.

See Item 7 of the accompanying Form 10-K for disclosures regarding liquidity and capital resources, 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]	
	2002	2001	2000	2002	2001
Sales Volumes					
Gas (Mcf)[b]					
Underlying properties	34,315,145	36,597,937	36,842,156	8,412,012	9,521,295
Average per day	94,014	100,268	100,662	91,435	103,492
Net profits interests	11,774,205	17,671,423	18,199,754	3,118,488	3,627,744
Oil (Bbls)[b]					
Underlying properties	353,185	393,731	399,929	83,016	95,063
Average per day	968	1,079	1,093	902	1,033
Net profits interests	123,142	190,722	198,677	31,466	38,698
Average Sales Prices					
Gas (per Mcf)	$ 2.44	$ 4.30	$ 3.14	$ 2.52	$ 2.19
Oil (per Bbl)	$23.70	$27.60	$28.67	$28.16	$25.02
Revenues					
Gas sales	$83,610,392	$157,508,999	$115,579,023	$21,228,671	$20,810,221
Oil sales	8,369,027	10,867,817	11,467,882	2,337,918	2,378,744
Total Revenues	**91,979,419**	**168,376,816**	**127,046,905**	**23,566,589**	**23,188,965**
Costs					
Taxes, transportation and other	8,228,963	15,694,068	12,023,222	2,477,308	2,078,658
Production expense	16,107,467	15,611,725	14,026,261	3,851,038	2,779,198
Development costs[c]	22,733,333	30,367,276	22,771,150	5,383,333	5,475,000
Overhead	7,551,912	7,921,077	7,211,096	1,491,634	2,221,354
Total Costs	**54,621,675**	**69,594,146**	**56,031,729**	**13,203,313**	**12,554,210**
Other Proceeds					
Property sales	60,000	307,824	–	–	–
Net Proceeds	37,417,744	99,090,494	71,015,176	10,363,276	10,634,755
Net Profits Percentage	80%	80%	80%	80%	80%
Net Profits Income	**$29,934,195**	**$ 79,272,395**	**$ 56,812,141**	**$ 8,290,621**	**$ 8,507,804**

(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, 2002, 2001 and 2000 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 expenses 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	
	2002	2001
Assets		
Cash and short-term investments	$ 3,227,840	$ 1,781,800
Net profits interests in oil and gas properties – net (Notes 1 and 2)	205,493,243	215,346,192
Total	**$208,721,083**	**$217,127,992**
Liabilities and Trust Corpus		
Distribution payable to unitholders	$ 3,227,840	$ 1,781,800
Trust corpus (40,000,000 units of beneficial interest authorized and outstanding)	205,493,243	215,346,192
Total	**$208,721,083**	**$217,127,992**

Statements of Distributable Income

		December 31	
	2002	2001	2000
Net profits income	$29,934,195	$79,272,395	$56,812,141
Interest income	14,955	136,177	128,150
Total income	29,949,150	79,408,572	56,940,291
Administration expense	376,790	277,532	228,211
Distributable income	**$29,572,360**	**$79,131,040**	**$56,712,080**
Distributable income per unit (40,000,000 units)	**$ 0.739309**	**$ 1.978276**	**$ 1.417802**

Statements of Changes in Trust Corpus

		Year Ended December 31	
	2002	2001	2000
Trust corpus, beginning of year	$215,346,192	$226,081,443	$233,428,609
Amortization of net profits interests	(9,852,949)	(10,735,251)	(7,347,166)
Distributable income	29,572,360	79,131,040	56,712,080
Distributions declared	(29,572,360)	(79,131,040)	(56,712,080)
Trust corpus, end of year	**$205,493,243**	**$215,346,192**	**$226,081,443**

See Accompanying Notes to Financial Statements.

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. XTO Energy currently owns and operates the majority of the underlying working interest properties.

In exchange for the conveyances of the net profits interests to the trust, 40 million units of beneficial interest in the trust 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 units to certain of its officers. The trust did not receive any proceeds from the sale of trust units.

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 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 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.

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 $41,573,708 as of December 31, 2002 and $31,720,759 as of December 31, 2001.

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 costs, development and drilling costs, and overhead (Note 6).

For monthly trust distributions declared through March 2000, the related net profits income was based on gross proceeds equal to the greater of:

- the actual amount received from sales of production, or
- the imputed amount that would be received from sales of production at a gas price of $2.00 per Mcf. For the year ended December 31, 2000, there were no imputed proceeds because actual gas prices were higher than the $2.00 price support.

XTO Energy, as owner of the underlying properties, computes net profits income separately for each of the three conveyances (Note 1). 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, the amount of development costs deducted in the calculation of net profits income and the cumulative actual development costs (over) under the amount deducted:

	Year Ended December 31	
	2002	2001
Cumulative development costs (over) under the amount deducted – beginning of period	$ (4,778,880)	$ -
Actual development costs	(14,864,890)	(35,146,156)
Amount deducted	22,733,333	30,367,276
Cumulative development costs (over) under the amount deducted – end of period	**$ 3,089,563**	**$ (4,778,880)**

Based on the 2003 budget, XTO Energy decreased the monthly development cost deduction from $1.9 million to $1 million beginning with the February 2003 distribution.

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.

XTO Energy has advised the trustee that the trust receives net profits income from tight sands gas wells. Production sold through 2002 from wells drilled on the underlying properties prior to January 1, 1993, and after November 5, 1990 (or after December 31, 1979 if the related formation was dedicated to interstate commerce as of April 20, 1977), qualifies for the federal income tax credit for producing nonconventional fuels under Section 29 of the Internal Revenue Code.

This tax credit was approximately $0.52 per MMBtu and $0.002991 per unit in 2002, $0.017309 per unit in 2001 and $0.014499 per unit in 2000. The credit is recalculated annually based on each year's qualifying production through the year 2002. Unitholders should consult their tax advisors regarding use of this credit and other trust tax compliance matters.

Congress has considered extending this credit beyond the December 31, 2002 expiration date, and the creation of similar new tax credits. Unless new legislation is passed, extending this credit on existing eligible production or allowing for credits on new production, there will be no further benefit on production past the year 2002.

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, 2002, the overhead charge was approximately $720,000 ($576,000 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. As of March 3, 2003, XTO Energy owned 54.3% of the trust.

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"). 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 $59.1 million for the year ended December 31, 2002, or 71% of total gas sales, $128.5 million for the year ended December 31, 2001, or 82% of total gas sales and $89.0 million for the year ended December 31, 2000, or 77% of total gas sales.

7. Litigation

XTO Energy is a defendant in two separate lawsuits that could, if adversely determined, decrease future trust distributable income. Any damages relating to production prior to December 1, 1998, the creation date of the trust, will be borne by XTO Energy.

On April 3, 1998, a class action lawsuit, *Booth, et al. v. Cross Timbers Oil Company,* was filed in the District Court of Dewey County, Oklahoma by royalty owners of natural gas wells in Oklahoma. The plaintiffs allege that since 1991, XTO Energy has underpaid royalty owners as a result of reducing royalties for improper charges for production, marketing, gathering, processing and transportation costs and selling natural gas through affiliated companies at prices less favorable than those paid by third parties. The parties have entered into a settlement agreement under which the trust's portion of the settlement will be approximately $850,000, or 2.1 cents per unit. This amount reflects the trust's 80% share of the settlement relating to production from the underlying properties for periods since December 1, 1998. The court has tentatively approved the settlement, subject to a fairness hearing in April 2003 and approval of the court. Assuming that no appeal is filed, and based on XTO Energy's anticipated settlement payment date of July 2003, this amount will reduce the trust's August 2003 distribution, which is paid to unitholders in September. The effect of the settlement on future distributions for other months will not be significant.

A second lawsuit, *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. This action 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 and wrongfully analyzing its heating content during at least the past ten years. The suit, which was brought under the *qui tam* provisions of the U.S. False Claims Act, seeks treble damages for the unpaid royalties (with interest), 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. The cases against XTO Energy and other defendants have been consolidated in the United States District Court for Wyoming. While XTO Energy is unable to predict the 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.

For further information regarding these lawsuits and other legal proceedings pertaining to the trust, see Item 3 of the trust's Annual Report on Form 10-K included in this report.

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 2002 and 2001:

	Net Profits Income	Distributable Income	Distributable Income per Unit
2002			
First Quarter	$ 7,412,420	$ 7,352,640	$0.183816
Second Quarter	5,560,186	5,334,640	0.133366
Third Quarter	8,670,968	8,622,680	0.215567
Fourth Quarter	8,290,621	8,262,400	0.206560
Total	**$29,934,195**	**$29,572,360**	**$0.739309**
2001			
First Quarter	$33,683,872	$33,654,480	$0.841362
Second Quarter	21,720,948	21,731,640	0.543291
Third Quarter	15,359,771	15,271,840	0.381796
Fourth Quarter	8,507,804	8,473,080	0.211827
Total	**$79,272,395**	**$79,131,040**	**$1.978276**

Independent Auditors' Reports

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, 2002, and the related statement of distributable income and changes in trust corpus for the year then ended. These financial statements are the responsibility of the trustee. Our responsibility is to express an opinion on these financial statements based on our audit. The 2001 and 2000 financial statements were audited by other auditors who have ceased operations. Those auditors' report, dated March 19, 2002, on those financial statements was unqualified and included an explanatory paragraph that described the trust's method of accounting as explained in Note 2 to the financial statements.

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

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

In our opinion, the 2002 financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the trust as of December 31, 2002 and its distributable income and changes in trust corpus for the year then ended in conformity with the modified cash basis of accounting described in Note 2.

KPMG LLP

KPMG LLP
March 14, 2003

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, 2001 and 2000, and the statements of distributable income and changes in trust corpus for each of the years then ended. These financial statements are the responsibility of the trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

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

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the trust as of December 31, 2001 and 2000 and its distributable income and changes in trust corpus for each of the years then ended, in conformity with the modified cash basis of accounting described in Note 2.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP, Fort Worth, Texas
March 19, 2002

The above report of Arthur Andersen LLP ("Arthur Andersen") is a copy of a report previously issued by Arthur Andersen on March 19, 2002. This audit report has not been reissued by Arthur Andersen in connection with this filing on Form 10-K. After reasonable effort, the trust has been unable to obtain the consent of Arthur Andersen, our former independent public accountants, as to the incorporation by reference of their report for our fiscal years ended December 31, 2001 and 2000 into the trust's and XTO Energy's previously filed registration statements under the Securities Act of 1933, and the trust has not filed that consent with this Annual Report on Form 10-K in reliance on Rule 437a of the Securities Act of 1933. Because the trust has not been able to obtain Arthur Andersen's consent, you will not be able to recover against Arthur Andersen under Section II of the Securities Act for any untrue statements of a material fact contained in our financial statements audited by Arthur Andersen or any omissions to state a material fact required to be stated therein.

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, 2002 — Commission file number 1-10476

Hugoton Royalty Trust

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

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes [X] 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 28, 2002 (the last business day of its most recently completed second fiscal quarter), held by non-affiliates of the registrant on that date was approximately $194 million.

At March 3, 2003, 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:

2002 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., 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. As of March 31, 2003, 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 (formerly known as Cross Timbers Oil Company) 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. As of March 3, 2003, XTO Energy owned 21,705,893 units in the trust. Units are listed and traded on the New York Stock Exchange under the symbol "HGT."

The net profits interests entitle the trust to receive 80% of 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, development and production costs and overhead. For trust distributions declared through March 2000, net proceeds from the sale of gas related to those distributions were contractually required to be computed differently. Net proceeds for this period were computed monthly based on the greater of either a realized price of $2.00 per Mcf or the actual price received by XTO Energy for natural gas sold.

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 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 net profits income payable to the trust for the next month will be reduced by the overpayment, plus interest at the prime rate.

To the extent it has the right to do so, 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 generally represents receipts 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 2002, as well as 94% of the estimated proved reserves of the net profits interests at December 31, 2002 (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 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.

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 the largest natural gas producing area in North America. More than 64 trillion cubic feet of natural gas have been produced from the Hugoton area. During 2002, sales volumes from the underlying properties in the Hugoton area averaged approximately 28,500 Mcf of gas per day and 77 Bbls of oil per day.

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, including the Council Grove between 2,950 and 3,400 feet, the Morrow between 6,000 and 6,300 feet, the Chester between 6,350 and 6,700 feet and the St. Louis between 7,500 and 8,000 feet. XTO Energy has participated in 3-D seismic shoots covering 30,000 acres of XTO Energy's net acreage position beneath the Chase formation. Test wells were drilled to delineate the Council Grove formation in 1999, 2000 and 2001.

During 2002, development of the Hugoton area included four successful recompletions to the Towanda formation. XTO Energy also continued its restimulation program in the Chase intervals, completing 33 of these restimulations in 2002. During 2003, XTO Energy plans to perform 35 Chase restimulations.

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

- additional compression to lower line pressures,
- pumping unit installations,
- opening new producing zones in existing wells,
- drilling additional wells,
- drilling deeper in existing wells to new producing zones, and
- restimulating producing intervals in existing wells utilizing new technology.

XTO Energy delivers most of its Hugoton gas production to a gathering and processing system operated by a subsidiary. This system collects approximately 75% of its throughput from underlying properties, which, in recent months, has been approximately 22,500 Mcf per day from 270 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 residue price received upon sale to XTO Energy's marketing affiliate. Under long-term contracts, the gathering subsidiary sells residue volumes to XTO Energy's marketing affiliate at a price equal to a published index and is reduced by any pipeline access fees incurred by the marketing affiliate, but is not reduced by any marketing fees. Pipeline access fees currently are approximately $0.015 per MMBtu.

Other Hugoton gas production is delivered 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 were discovered in the Anadarko Basin of western Oklahoma in 1945. Daily sales volumes from the underlying properties in the Anadarko Basin averaged 42,100 Mcf and 845 Bbls in 2002. XTO Energy is one of the largest producers in the Ringwood, Northwest Okeene and Cheyenne Valley fields in Major County, the principal producing region of the underlying properties in the Anadarko Basin.

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.

In Major and Woodward counties, the Mississippian (Osage), Chester and Red Fork formations were the primary drilling targets in 2002. In Major County, XTO Energy successfully drilled seven gross (4.9 net) wells. XTO Energy plans to drill up to six wells and perform up to 11 workovers in Major County during the next year. In Woodward County, the Chester formation, with its four separate producing intervals, was the primary target for ten gross (8.0 net) wells successfully drilled and completed during 2002. During 2003, XTO Energy plans to drill up to 12 gross (11.5 net) wells and perform up to five workovers in Woodward County.

XTO Energy plans to further develop the underlying properties in the Major County area 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 the average price of several published indices. 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 2002, the gathering system collected approximately 19,500 Mcf per day from over 400 wells, 70% of which XTO Energy operates. Estimated capacity of the gathering system is 40,000 Mcf per day. The gathering subsidiary also provides contract operating services to properties in Woodward County, collecting approximately 8,300 Mcf per day from 61 wells, for a historical average fee of approximately $0.12 per Mcf.

XTO Energy also sells gas 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.

In 2002, daily sales volumes from the underlying properties in the Fontenelle Field averaged 23,400 Mcf of natural gas and 46 Bbls of oil. XTO Energy has informed the trustee that its development activities in the Fontenelle Field were delayed for the better part of 2002 due to the pipeline limitations and price volatility. XTO Energy plans to perform up to five workovers and may drill up to five wells in the Green River Basin during 2003.

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,
- opening new producing zones in existing wells,
- deepening existing wells to new producing zones, and
- drilling additional wells.

XTO Energy markets the gas produced from the Fontenelle Unit and nearby properties under three different marketing arrangements. Under the agreement covering 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 2002, the fuel charge was 0.025% of the volumes produced and the processing fee was $0.051 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 $0.148 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.

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, 2002. 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, 2002:

	Operated Wells		Nonoperated Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Gas	1,088	989.5	270	62.8	1,358	1,052.3
Oil	126	113.7	7	1.7	133	115.4
Total	1,214	1,103.2	277	64.5	1,491	1,167.7

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 two gross (0.7 net) wells in process of drilling at December 31, 2002.

	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Completed gas wells (a)	24	15.4	46	34.1	40	31.0
Completed oil wells (b)	—	—	—	—	1	0.1
Total	24	15.4	46	34.1	41	31.1

(a) Included in completed gas wells are wells drilled on nonoperated interests totaling 6 gross (0.48 net) in 2002, 6 gross (1.3 net) in 2001 and 10 gross (1.7 net) in 2000.

(b) Completed oil wells were drilled on nonoperated interests.

Oil and 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, 2002 were as follows:

	2002	2001	2000
Production			
Underlying Properties			
Gas—Sales (Mcf)	34,315,145	36,597,937	36,842,156
Average per day (Mcf)	94,014	100,268	100,662
Oil—Sales (Bbls)	353,185	393,731	399,929
Average per day (Bbls)	968	1,079	1,093
Net Profits Interests			
Gas—Sales (Mcf)	11,774,205	17,671,423	18,199,754
Average per day (Mcf)	32,258	48,415	49,726
Oil—Sales (Bbls)	123,142	190,722	198,677
Average per day (Bbls)	337	523	543
Average Sales Price			
Gas (per Mcf)	$ 2.44	$ 4.30	$ 3.14
Oil (per Bbl)	$23.70	$27.60	$28.67

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, 2002, 2001, 2000 and 1999. 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, excluding overhead. 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.

Year-end weighted average realized gas prices used to determine the standardized measure were $4.37 per Mcf in 2002, $2.34 per Mcf in 2001, $9.44 per Mcf in 2000 and $2.23 per Mcf in 1999. Year-end oil prices used to determine the standardized measure were based on a West Texas Intermediate crude oil posted price of $28.00 per Bbl in 2002, $16.75 per Bbl in 2001, $23.75 per Bbl in 2000 and $22.75 per Bbl in 1999.

Proved Reserves

(in thousands)	Underlying Properties		Net Profits Interests	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
Balance, December 31, 1999	505,369	4,271	287,921	2,411
Extensions, discoveries and other additions	29,076	132	20,605	94
Revisions of prior estimates	17,640	544	81,922	957
Property sales	(225)	(10)	(98)	(4)
Production—sales volumes	(36,842)	(400)	(18,200)	(199)
Balance, December 31, 2000	515,018	4,537	372,150	3,259
Extensions, discoveries and other additions	18,365	65	8,270	29
Revisions of prior estimates	(26,582)	(390)	(105,407)	(1,001)
Production—sales volumes	(36,598)	(394)	(17,671)	(191)
Balance, December 31, 2001	470,203	3,818	257,342	2,096
Extensions, discoveries and other additions	12,076	117	6,979	68
Revisions of prior estimates	28,582	531	46,671	561
Property sales	(45)	(2)	(21)	(1)
Production—sales volumes	(34,315)	(353)	(11,774)	(123)
Balance, December 31, 2002	476,501	4,111	299,197	2,601

Extensions, discoveries and additions in 2000, 2001 and 2002 are primarily related to delineation of additional proved undeveloped reserves in the Anadarko Basin. Revisions of prior estimates of the proved reserves for the underlying properties in each year are primarily because of changes in the year-end gas price. Higher upward and downward revisions for the net profits interests as compared with the underlying properties in each year were caused by changes in the year-end gas price which resulted in increased gas reserves allocated to or from the trust.

Proved Developed Reserves

(in thousands)	Underlying Properties		Net Profits Interests	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
December 31, 1999	431,399	3,595	253,567	2,105
December 31, 2000	434,904	3,935	316,278	2,843
December 31, 2001	401,846	3,297	228,472	1,876
December 31, 2002	407,959	3,580	260,806	2,296

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)	December 31		
	2002	2001	2000
Underlying Properties			
Future cash inflows	$2,193,359	$1,177,447	$4,972,727
Future costs:			
Production	566,527	389,721	831,037
Development	56,864	55,072	60,211
Future net cash flows	1,569,968	732,654	4,081,479
10% discount factor	808,082	365,760	2,141,117
Standardized measure	$ 761,886	$ 366,894	$1,940,362
Net Profits Interests			
Future cash inflows	$1,378,842	$ 644,489	$3,593,473
Future production taxes	122,868	58,366	328,290
Future net cash flows	1,255,974	586,123	3,265,183
10% discount factor	646,465	292,608	1,712,894
Standardized measure	$ 609,509	$ 293,515	$1,552,289

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

(in thousands)	2002	2001	2000
Underlying Properties			
Standardized measure, January 1	$366,894	$ 1,940,362	$ 408,768
Revisions:			
Prices and costs	387,989	(1,626,755)	1,496,302
Quantity estimates	16,136	(2,367)	(5,187)
Accretion of discount	32,022	166,273	35,746
Future development costs	(20,105)	(20,415)	(30,339)
Production rates and other	(47)	362	283
Net revisions	415,995	(1,482,902)	1,496,805
Extensions, additions and discoveries	16,467	8,524	105,929
Production	(60,151)	(129,457)	(93,786)
Development costs	22,733	30,367	22,771
Sales in place	(52)	—	(125)
Net change	394,992	(1,573,468)	1,531,594
Standardized measure, December 31	$761,886	$ 366,894	$1,940,362
Net Profits Interests			
Standardized measure, January 1	$293,515	$ 1,552,289	$ 327,014
Extensions, discoveries and other additions	13,173	6,819	84,743
Accretion of discount	25,618	133,018	28,597
Revisions of prior estimates, changes in price and other (a)	307,178	(1,319,339)	1,168,847
Property sales	(41)	—	(100)
Net profits income	(29,934)	(79,272)	(56,812)
Standardized measure, December 31	$609,509	$ 293,515	$1,552,289

(a) Significant revisions in 2002, 2001 and 2000 were caused by the changes in year-end gas prices.

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. 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.

Other Regulation

The Minerals Management Service of the United States Department of the Interior continues to evaluate existing methods of settling royalties on federal and Native American oil and gas leases. Seven percent of the net acres of the underlying properties, primarily located in Wyoming, involve federal leases. Although a change in the final rules could cause an increase in the federal royalties to be paid on these properties, and, correspondingly, decrease the revenue to XTO Energy and the trust, XTO Energy's management does not believe that any rule changes will have a significant detrimental 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.

Tight Sands Tax Credit

The trust receives net profits income from tight sands wells, certain production from which qualifies for the federal income tax credit for producing nonconventional fuels under Section 29 of the Internal Revenue Code. The Section 29 tax credit is available for tight sands gas produced and sold through 2002 from wells drilled prior to January 1, 1993 and after November 5, 1990, or after December 31, 1979 if the related formation was dedicated to interstate commerce as of April 20, 1977. This tax credit is approximately $0.52 per MMBtu. Such credit, calculated based on the unitholder's pro rata share of qualifying production, may not reduce the unitholder's regular tax liability (after the foreign tax credit and certain other nonrefundable credits) below his tentative minimum tax. Any part of the Section 29 credit not allowed for the tax year solely because of this limitation is subject to certain carryover provisions.

Congress has considered extending this credit beyond the December 31, 2002 expiration date, and the creation of similar new tax credits. Unless new legislation is passed, extending this credit on existing eligible production or allowing for credits on new production, there will be no further benefit on production past the year 2002.

Pricing and Sales Information

A subsidiary of XTO Energy purchases most of XTO Energy's natural gas production at the monthly published index price, then sells the gas to third parties for the best available price. 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 expires in 2004. 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 April 3, 1998, a class action lawsuit, *Booth, et al. v. Cross Timbers Oil Company*, was filed in the District Court of Dewey County, Oklahoma by royalty owners of natural gas wells in Oklahoma. The plaintiffs allege that since 1991, XTO Energy, formerly known as Cross Timbers Oil Company, has underpaid royalty owners as a result of reducing royalties for improper charges for production, marketing, gathering, processing and transportation costs and selling natural gas through affiliated companies at prices less favorable than those paid by third parties. The parties have entered into a settlement agreement under which the trust's portion of the settlement will be approximately $850,000, or 2.1 cents per unit. This amount reflects the trust's 80% share of the settlement relating to production from the underlying properties for periods since December 1, 1998. The court has tentatively approved the settlement, subject to a fairness hearing in April 2003 and approval of the court. Assuming that no appeal is filed, and based on XTO Energy's anticipated settlement payment date of July 2003, this amount will reduce the trust's August 2003 distribution, which is paid to unitholders in September. The effect of the settlement on future distributions for other months will not be significant.

A second lawsuit, *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. This action 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 and wrongfully analyzing its heating content during at least the past ten years. The suit, which was brought under the *qui tam* provisions of the U.S. False Claims Act, seeks treble damages for the unpaid royalties (with interest), 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. The cases against XTO Energy and other defendants have been consolidated in the United States District Court for Wyoming. While XTO Energy is unable to predict the 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.

Certain of the trust 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 2002.

PART II

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

The section entitled "Units of Beneficial Interest" on page 1 of the trust's annual report to unitholders for the year ended December 31, 2002 is incorporated herein by reference.

Item 6. *Selected Financial Data*

	Year Ended December 31			
	2002	2001	2000	1999
Net Profits Income	$ 29,934,195	$ 79,272,395	$ 56,812,141	$ 33,139,662
Distributable Income	29,572,360	79,131,040	56,712,080	33,090,049
Distributable Income per Unit	0.739309	1.978276	1.417802	0.827253
Distributions per Unit	0.739309	1.978276	1.417802	0.827253
Total Assets at Year-End	208,721,083	217,127,992	232,057,603	237,980,449

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, 2002 on pages 5 and 6 of the trust's annual report to unitholders for the year ended December 31, 2002 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.

Contractual Obligations and Commitments

The trust had no obligations and commitments to make future contractual payments as of December 31, 2002, other than the December distribution payable to unitholders in January 2003, as reflected in the statement of assets, liabilities and trust corpus. 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. Additionally, the trust has no off balance sheet financing arrangements.

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, 2002, the monthly overhead charge was approximately $720,000 ($576,000 net to the trust) and is subject to annual adjustment based on an oil and gas industry index. As of March 3, 2003, XTO Energy owned 21,705,893, or 54.3%, of the 40,000,000 outstanding units.

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, 2002. Total gas sales from the underlying properties to XTO Energy's wholly owned subsidiaries were $59.1 million for the year ended December 31, 2002, or 71% of total gas sales, $128.5 million for the year ended December 31, 2001, or 82% of total gas sales and $89.0 million for the year ended December 31, 2000, or 77% 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 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 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.

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, 2002.

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 non-exchange trade values.

Oil and Gas Reserves

The trust's proved oil and gas reserves are estimated by independent petroleum engineers. 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, 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 discussed below.

Oil and Gas Price Fluctuations. The trust's monthly cash distributions are highly dependent upon the prices realized from the sale of gas and, to a lesser extent, oil. Oil and 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 foreign oil and gas, consumer demand, and the price and availability of alternative fuels. Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices in the long term. Lower oil and gas prices may reduce the amount of oil and 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.

Increased Production and Development Costs. Production and development costs are deducted in the calculation of the trust's share of net proceeds. Accordingly, higher or lower production and development costs, without concurrent increases in revenue, will directly decrease or increase the amount received by the trust for its net profits interests. If development and production costs 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.

Reserve Estimates. Estimating reserves is inherently uncertain. Petroleum engineers consider many factors and make assumptions in estimating reserves and future net cash flows. 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 variations could be material. The trust's reserve quantities are based on estimates of reserves for the underlying properties. The method of allocating a portion of those reserves to the trust is complicated because the trust holds an interest in net profits and does not own a specific percentage of the oil and gas reserves.

Operating Risks. The occurrence of drilling, production or transportation accidents at any of the underlying properties will reduce trust distributions by the amount of uninsured costs. These accidents may result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any uninsured costs would be deducted as production costs in calculating net proceeds payable to the trust.

Trust's Assets are Depleting Assets. The net proceeds payable to the trust are derived from the sale of depleting assets. Accordingly, the portion of the distributions to trust unitholders attributable to depletion may be considered a return of capital. 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 gas. If operators of the properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by XTO Energy.

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 March 14, 2003 and Arthur Andersen LLP dated March 19, 2002, appearing on pages 8 through 12 of the trust's annual report to unitholders for the year ended December 31, 2002 are incorporated herein by reference.

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

On June 25, 2002, the trustee appointed KPMG LLP as independent auditors for fiscal year 2002 to replace Arthur Andersen LLP, effective with such appointment. Information regarding this change in independent auditors is included in the trust's current report on Form 8-K dated June 25, 2002.

There have been no other changes in accountants and there have been no disagreements with accountants on any matter of accounting principles or practices or financial statement disclosures during the two years ended December 31, 2002.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

The trust has no directors or executive officers. 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.

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, 2002. The trust has determined that Mr. Bob R. Simpson, Chairman and Chief Executive Officer of XTO Energy Inc., had four late filings with respect to one transaction in trust units during 1999. The transaction occurred prior to the date the Securities and Exchange Commission took the position that officers and directors of XTO Energy may be subject to the filing requirements of Section 16(a) with respect to transactions in trust units. The transaction has now been reported.

Item 11. *Executive Compensation*

The trustee received the following annual compensation from 2000 through 2002 as specified in the trust indenture:

Name and Principal Position	Year	Other Annual Compensation (1)
Bank of America, N.A., Trustee	2002	$35,000
	2001	35,000
	2000	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 following table sets forth as of March 3, 2003 information with respect to each person known to the trustee to beneficially own more than 5% of the outstanding units of the trust:

Name and Address	Amount and Nature of Beneficial Ownership	Percent of Class
XTO Energy Inc. 810 Houston Street, Suite 2000 Fort Worth, Texas 76102	21,705,893 units (1)	54.3%

(1) XTO Energy has the sole power to vote and dispose of these units.

(b) *Security Ownership of Management.* The trust has no directors or executive officers. As of February 28, 2003, Bank of America, N.A. owned, in various fiduciary capacities, 98,300 units with a shared right to vote 35,300 of these units and no right to vote 63,000 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, 2002 was approximately $720,000 per month, or $8,640,000 annually (net to the trust of $576,000 per month or $6,912,000 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.

Item 14. *Controls and Procedures*

Within the 90 days prior to the date of this report, the trustee carried out an evaluation of the effectiveness of the design and operation of the trust's disclosure controls and procedures pursuant to Exchange Act Rule 13a-14. Based upon that evaluation, the trustee concluded that the trust's disclosure controls and procedures are effective in timely alerting the trustee to material information relating to the trust required to be included in the trust's periodic filings with the Securities and Exchange Commission. In its evaluation of disclosure controls and procedures, the trustee has relied, to the extent considered reasonable, on information provided by XTO Energy. No significant changes in the trust's internal controls or other factors that could affect these controls have occurred subsequent to the date of such evaluation.

PART IV

Item 15. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(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 Auditors' Reports
   Statements of Assets, Liabilities and Trust Corpus at December 31, 2002 and 2001
   Statements of Distributable Income for the years ended December 31, 2002, 2001 and 2000
   Statements of Changes in Trust Corpus for the years ended December 31, 2002, 2001 and 2000
   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 Inc.) 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 Inc.) 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 Inc.) 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 Inc.) 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, 2002

(23.1) Consent of KPMG LLP

(23.2) Notice Regarding Consent of Arthur Andersen LLP

(23.3) Consent of Miller and Lents, Ltd.

(99.1) Trustee certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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.

(b) Reports on Form 8-K

During the last quarter of the trust's fiscal year ended December 31, 2002, there were no reports filed on Form 8-K by the trust with the Securities and Exchange Commission.

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: NANCY G. WILLIS
Nancy G. Willis
Assistant Vice President

XTO ENERGY INC.

Date: March 31, 2003

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

(The trust has no directors or executive officers.)

CERTIFICATIONS

I, Nancy G. Willis, certify that:

1. I have reviewed this Annual Report on Form 10-K of Hugoton Royalty Trust, for which Bank of America, N.A. acts as Trustee;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, distributable income and changes in trust corpus of the registrant as of, and for, the periods presented in this annual report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14), or for causing such procedures to be established and maintained, for the registrant and I have:

   a) designed such disclosure controls and procedures, or caused such controls and procedures to be designed, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report my conclusions about the effectiveness of the disclosure controls and procedures based on my evaluation as of the Evaluation Date;

5. I have disclosed, based on my most recent evaluation, to the registrant's auditors:

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves persons who have a significant role in the registrant's internal controls; and

6. I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of my most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

In giving the certifications in paragraphs 4, 5 and 6 above, I have relied to the extent I consider reasonable on information provided to me by XTO Energy Inc.

Date: March 31, 2003

By

/s/ NANCY G. WILLIS

Nancy G. Willis
Assistant Vice President
Bank of America, N.A.

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.

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.
Dallas, Texas
www.melloninvestor.com

Hugoton

ROYALTY TRUST

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