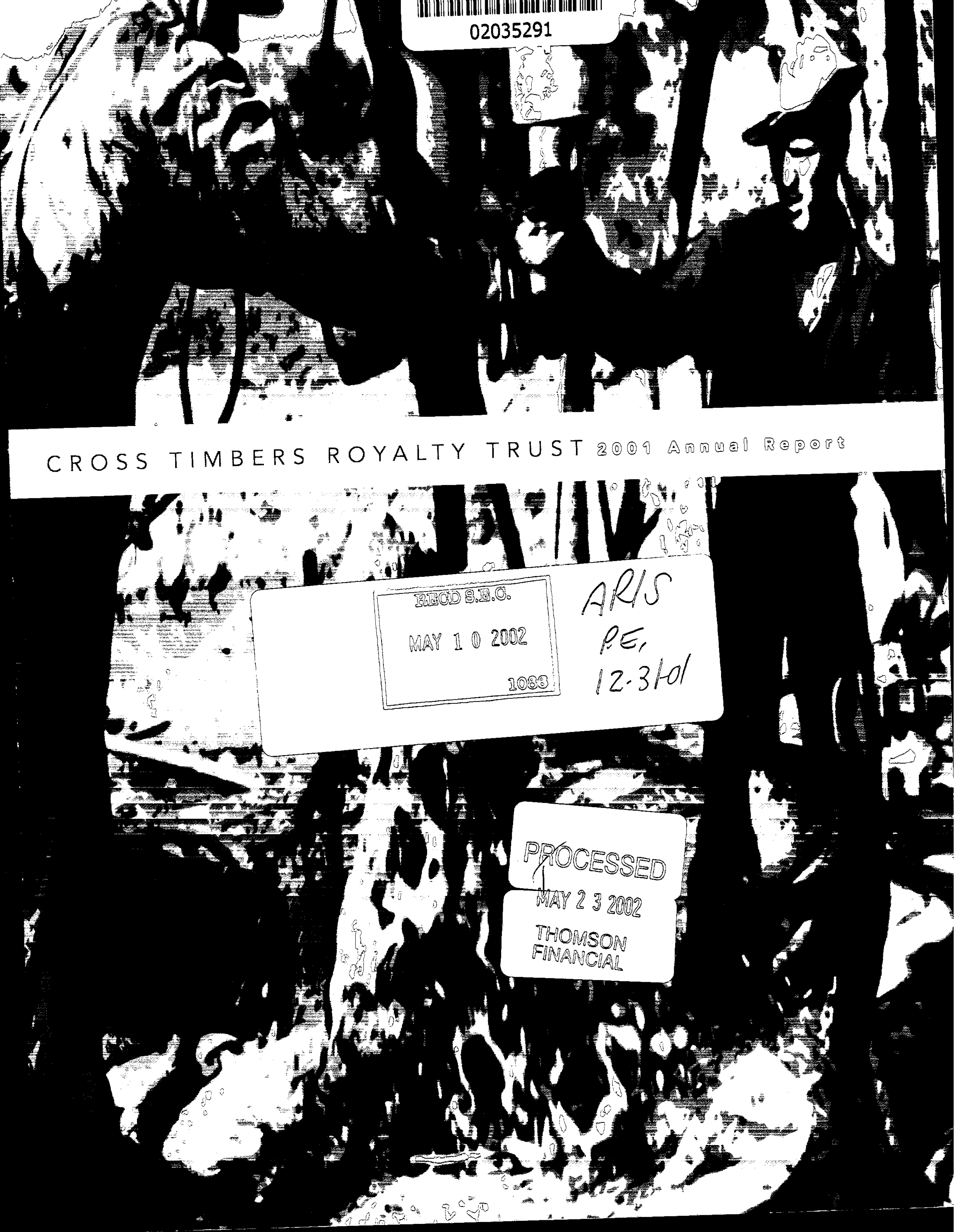


CROSS TIMBERS ROYALTY TRUST 2001 Annual Report

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 applicable net profits percentage of 75% or 90% and paid to the trust by XTO Energy. "Net profits income" is referred to as "royalty income" for income tax 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:

90% net profits interests – interests that entitle the trust to receive 90% of the net proceeds from the underlying properties that are royalty or overriding royalty interests in Texas, Oklahoma and New Mexico

75% net profits interests – interests that entitle the trust to receive 75% of the net proceeds from the underlying properties that are working interests in Texas and Oklahoma

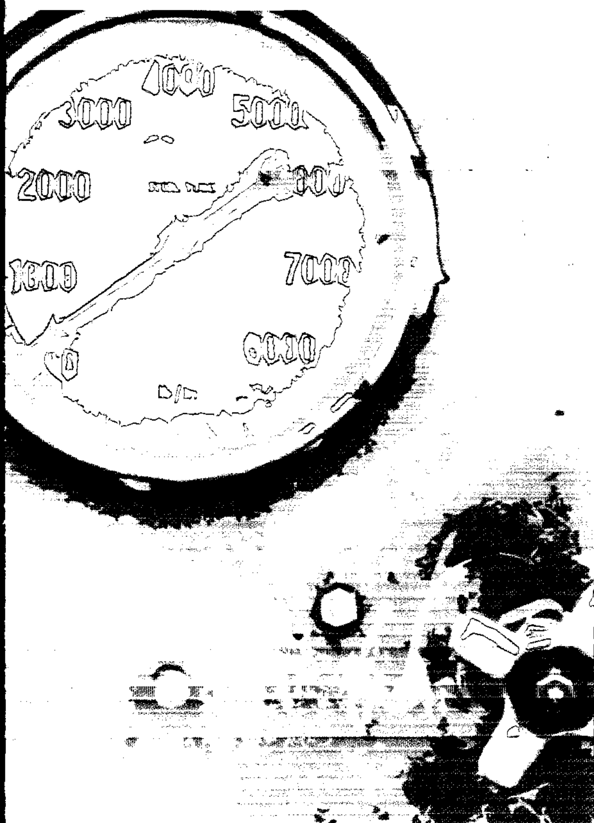
royalty interest (and overriding royalty interest) A nonoperating interest in an oil and gas property that provides the owner a specified share of production without any production or development costs

underlying properties XTO Energy's interest in certain oil and gas properties from which the net profits interests were conveyed. The underlying properties include royalty and overriding royalty interests in producing and nonproducing properties in Texas, Oklahoma and New Mexico, and working interests in producing properties located in Texas and Oklahoma.

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

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 believes 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.



by conveyance of 90% net profits interests in certain royalty and overriding royalty interest properties in Texas, Oklahoma and New Mexico, and 75% net profits interests in certain working interest properties in Texas and Oklahoma. XTO Energy Inc. (formerly known as Cross Timbers Oil Company) owns the underlying properties from which these net profits interests were conveyed. 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 are listed and traded on the New York Stock Exchange under the symbol "CRT." The following are the high and low unit sales prices and total cash distributions per unit paid by the trust during each quarter of 2001 and 2000:

	SALES PRICE HIGH	SALES PRICE LOW	DISTRIBUTIONS PER UNIT
2001			
First Quarter	$ 18.950	$ 15.500	$ 0.674817
Second Quarter	23.200	15.250	0.696495
Third Quarter	20.050	15.230	0.566440
Fourth Quarter	18.800	15.050	0.430562
			$ 2.368314
2000			
First Quarter	$ 14.750	$ 9.500	$ 0.383466
Second Quarter	14.188	10.438	0.404105
Third Quarter	17.000	13.000	0.557722
Fourth Quarter	16.938	13.375	0.571726
			$ 1.917019

At December 31, 2001, there were 6,000,000 units outstanding and approximately 175 unitholders of record; 5,595,758 of these units were held by a depository institution. As of March 1, 2002, XTO Energy owned 1,360,000 units.

income is received from two major components, the 90% net profits interests and the 75% net profits interests.

☐ ***The 90% net profits interests*** were conveyed from underlying royalty and overriding royalty interests in producing properties in Texas, Oklahoma and New Mexico. Most net profits income is from long-lived gas properties in the San Juan Basin of northwestern New Mexico. Because the 90% net profits interests are not subject to production or development costs, net profits income from these interests generally only varies because of changes in sales volumes or prices.

☐ ***The 75% net profits interests*** were conveyed from underlying working interests in seven large, predominantly oil-producing properties in Texas and Oklahoma. Net profits income from these properties is reduced by production and development costs. If costs exceed revenues from the underlying working interest properties in either Texas or Oklahoma, the 75% net profits interests for that state will not contribute to trust net profits income until all excess costs and accrued interest have been recovered from future net proceeds of that state. However, such excess costs will not reduce net profits income from the other 75% net profits interests or from the 90% net profits interests. Because of excess costs, the Texas 75% net profits interests did not contribute to trust net profits income in 1999 and through April 2000, and the Oklahoma 75% net profits interests did not contribute to trust net profits income from February through June 1999 and for September 1999. Such excess costs generally occur during periods of higher development activity and lower oil prices. For further information, see "Trustee's Discussion and Analysis – Years Ended December 31, 2001, 2000 and 1999 – Costs."

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 coal seam gas production through the year 2002 from wells drilled on the properties underlying the 90% net profits interests after December 31, 1979 and prior to January 1, 1993. Unitholders are entitled to this tax credit (also referred to as "coal seam tax credit") which may be used to reduce the unitholder's regular income tax liability, but not below his tentative minimum tax. Congress is considering an extension of existing energy tax credits beyond the scheduled December 31, 2002 expiration date, as well as the creation of similar new tax credits. During 2001, the U.S. House passed a bill that would extend existing tax credits on certain production, while the U.S. Senate is considering a separate bill to address energy tax credits. The potential effect of any final legislation on unitholders is unknown.

☐ ***Cost Depletion*** is generally available to unitholders as a deduction from net profits 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 2001 and held them throughout 2001 would be entitled to a cost depletion deduction of approximately 8% of his cost. Assuming a cost of $18.00 per unit, cost depletion would offset 59% of 2001 taxable trust income. After considering the coal seam tax credit and assuming a 30% tax rate, the 2001 taxable equivalent return as a percentage of unit cost would be 17%. (NOTE: Because the units are a depleting asset, a portion of this return is effectively a return of capital.)

Distribution Summary

The following summarizes the effect of the above components on distributions per unit for the last three years:

	2001		2000		1999	
	MONTHLY AVERAGE	**ANNUAL TOTAL**	**MONTHLY AVERAGE**	**ANNUAL TOTAL**	**MONTHLY AVERAGE**	**ANNUAL TOTAL**
NET PROFITS INCOME						
90% Net Profits Interests	$ 0.178	$ 2.130	$ 0.129	$ 1.550	$ 0.088	$ 1.055
75% Net Profits Interests	0.022	0.268	0.033	0.393	0.005	0.060
Administration Expense (net of interest income)	(0.003)	(0.030)	(0.002)	(0.026)	(0.002)	(0.023)
TOTAL DISTRIBUTION	$ 0.197	$ 2.368	$ 0.160	$ 1.917	$ 0.091	$ 1.092
Nonconventional Fuel Source Tax Credit	*	$ 0.107	*	$ 0.120	*	$ 0.158

*Not applicable

TO UNITHOLDERS

We are pleased to present the 2001 Annual Report of Cross Timbers Royalty Trust and Form 10-K. 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, 2001, net profits income totaled $14,389,316. After deducting trust administration expense and adding interest income, distributable income was $14,209,884, or $2.368314 per unit. Distributions for the year were the highest since the trust's inception and were 24% higher than in 2000 primarily because of higher average gas prices.

Natural gas prices for 2001 averaged $5.09 per Mcf for sales from the underlying properties, a 53% increase from the 2000 average price of $3.32 per Mcf. Gas sales volumes from the underlying properties for the year ended December 31, 2001 totaled 2,932,203 Mcf, or 8,033 Mcf per day, a 5% decrease from 2000 production of 8,417 Mcf per day. Gas volumes were lower primarily because of coal seam gas production decline.

Oil sales volumes from the underlying properties during 2001 were 350,691 Bbls, or 961 Bbls per day, a 2% increase over 2000 levels of 940 Bbls per day. The average oil price decreased to $24.99 per Bbl, down 9% from the 2000 average price of $27.49.

Coal seam gas sales volumes from the underlying properties were 744,092 Mcf in 2001, or a 15% decline from 2000 coal seam gas production of 874,819 Mcf. Coal seam gas sales volumes are lower because of natural production decline. The resulting 2001 coal seam tax credit was $0.107183 per unit. This credit (or a portion thereof, if units were held less than the full year) is available to be applied against a 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, 2001, proved reserves of the net profits interests were estimated by independent engineers to be 1,299,000 Bbls of oil and 31.7 Bcf of natural gas. Estimated oil reserves and gas reserves decreased 38% and 9%, respectively, from year-end 2000 to 2001 primarily because of lower oil and gas prices. All reserve information prepared by independent engineers has been provided to the trustee by XTO Energy.

Estimated future net revenues from proved reserves of the net profits interests at December 31, 2001 are $91.5 million, or $15.26 per unit. Using an annual discount factor of 10%, the present value of estimated future net revenues at December 31, 2001 is $44.0 million, or $7.34 per unit. Proved reserve estimates and related future net revenues have been determined based on a year-end West Texas Intermediate posted oil price of $16.75 per barrel and a year-end average realized gas price of $2.28 per Mcf. Other guidelines used in estimating proved reserves, as prescribed by the Financial Accounting Standards Board, are described under Item 2 of the accompanying Form 10-K. The present value of estimated future net revenues is not necessarily indicative of the market value of trust units.

As discussed in the tax instructions provided to unitholders in February 2002, trust distributions are considered portfolio income, rather than passive income. Unitholders should consult their tax advisors for further information.

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

By:

Ron E. Hooper
Senior Vice President

The underlying properties include over 2,900 producing properties with established production histories in Texas, Oklahoma and New Mexico. The average reserve-to-production index for the underlying properties as of December 31, 2001 is approximately 12 years for oil and gas. This index is calculated using total proved reserves and estimated 2002 production for the underlying properties. Based on estimated future net revenues at year-end oil and gas prices, the proved reserves of the underlying properties are approximately 24% oil and 76% natural gas. The underlying properties also include certain nonproducing properties in Texas, Oklahoma and New Mexico that are primarily mineral interests. XTO Energy cannot significantly influence or control the operations of the underlying properties.

90% NET PROFITS INTERESTS

Royalty and overriding royalty properties underlying the 90% net profits interests represent 86% of the discounted future net cash flows from trust proved reserves at December 31, 2001. Approximately 88% of the discounted future net cash flows from the 90% net profits interests is from gas reserves, totaling 31.4 Bcf. Oil reserves underlying the 90% net profits interests are primarily located in West Texas and are estimated to be 614,000 Bbls at December 31, 2001.

Because the properties underlying the 90% net profits interests are royalty interests and overriding royalty interests, net profits income from these properties is not reduced by production and development costs. Additionally, net profits income from these interests cannot be reduced by any excess costs of the 75% net profits interests. The trust, therefore, should generally receive monthly net profits income from these interests, as determined by oil and gas sales volumes and prices.

Most of the trust's gas reserves are located in the San Juan Basin of northwestern New Mexico, one of the largest domestic gas fields. The San Juan Basin royalties produced approximately 77% of gas sales volumes and 63% of net profits income for 2001. As of December 31, 2001, trust proved reserves in this region are estimated to be 26.1 Bcf, or 82% of total trust gas reserves.

Approximately 26% of trust 2001 gas sales volumes were from coal seam production in the San Juan Basin. Through the year 2002, sales of production from coal seam wells drilled after December 31, 1979 and prior to January 1, 1993 qualify for a federal income tax credit under Section 29 of the Internal Revenue Code for nonconventional fuel sources. This credit for 2001 coal seam gas sales was approximately $1.08 per MMBtu or $0.107183 per unit, while the coal seam credit for 2000 was $1.06 per MMBtu or $0.120389 per unit. As of December 31, 2001, the trust's proved coal seam gas reserves are estimated to be 3.9 Bcf, as compared with 4.4 Bcf at December 31, 2000.

Congress is considering an extension of existing energy tax credits beyond the scheduled December 31, 2002 expiration date, as well as the creation of similar new tax credits. During 2001, the U.S. House passed a bill that would extend existing tax credits on certain production, while the U.S. Senate is considering a separate bill to address energy tax credits. The potential effect of any final legislation on unitholders is unknown.

Operators are seeking approval to increase the density of coal seam wells drilled in the San Juan Basin. XTO Energy anticipates that hearings on the request will be held in June 2002. Although XTO Energy believes that the outlook for approval of increased density drilling is good, there can be no assurance that such an increase will be approved.

Most of the trust's San Juan Basin conventional, or non-coal seam, production is from the Mesaverde formation. This formation has been approved for increased density drilling, doubling the number of drill wells allowed to four per spacing unit. XTO Energy has advised the trustee that it believes operators will further develop the Mesaverde formation underlying the net profits interests, and such future development could significantly impact underlying gas sales volumes. There was minimal drilling in 2001 because of environmental concerns that delayed approval of drilling permits.

75% NET PROFITS INTERESTS

Underlying the 75% net profits interests are working interests in seven large properties in Texas and Oklahoma operated primarily by established oil companies. These properties are located in mature fields undergoing secondary or tertiary recovery operations. With its relatively minor working interest, XTO Energy generally has little influence or control over operations on any of these properties.

Proved reserves from the 75% net profits interests are almost entirely oil, estimated to be approximately 685,000 Bbls at year-end 2001. Based on year-end oil and gas prices, proved reserves from these interests represent 14% of the discounted future net cash flows of the trust's proved reserves at December 31, 2001.

Because these underlying properties are working interests, production and development costs are deducted in calculating net profits income from the 75% net profits interests. As a result, net profits income from these interests is affected by the level of maintenance and development activity on these underlying properties. Net profits income is also dependent upon oil sales volumes and prices and is subject to reduction for any prior period excess costs.

Total 2001 development costs were $1,133,869, up 54% from 2000 development costs of $738,605. First quarter 2002 development costs totaled approximately $286,000; these costs are primarily related to fourth quarter 2001 expenditures.

As reported to XTO Energy by unit operators in February of each year, budgeted development costs were $896,000 for 2001 and $356,000 for 2000. Actual development costs often differ from amounts budgeted because of changes in product prices that may affect the timing of projects. Also, costs are deducted in the calculation of trust net profits income several months after they are incurred by the operator. Unit operators have reported total budgeted costs, net to XTO Energy's interests, of approximately $417,000 for 2002 and $204,000 for 2003.

Higher development costs and lower oil prices during 1998 and early 1999 caused costs to exceed revenues from the properties underlying the 75% net profits interests. During 1999 and 2000, $1,018,113 ($763,585 net to the trust) of such excess costs and accrued interest were recovered. There were no excess costs in 2001. In February and March 2002, total excess costs and accrued interest of $71,000 were incurred on the Texas 75% net profits interests as a result of lower oil prices and increased development costs. For information regarding the effect of excess costs on trust net profits income, see "Trustee's Discussion and Analysis – Years Ended December 31, 2001, 2000 and 1999 – Costs."

Estimated Proved Reserves and Future Net Revenues

The following are proved reserves of the underlying properties and proved reserves and future net revenues from proved reserves of the net profits interests at December 31, 2001, as estimated by independent engineers:

(IN THOUSANDS)	UNDERLYING PROPERTIES		NET PROFITS INTERESTS			
	PROVED RESERVES [A]		PROVED RESERVES [A] [B]		FUTURE NET REVENUES FROM PROVED RESERVES [A] [C]	
	OIL [BBLS]	GAS [MCF]	OIL [BBLS]	GAS [MCF]	UNDISCOUNTED	DISCOUNTED
90% NET PROFITS INTERESTS						
San Juan Basin						
Conventional	66	24,661	59	22,195	$ 53,323	$ 22,487
Coal Seam	-	4,336	-	3,902	5,564	3,688
Total	66	28,997	59	26,097	58,887	26,175
Other New Mexico	125	294	112	248	2,435	1,427
Texas	425	3,795	383	3,410	14,216	8,003
Oklahoma	67	1,886	60	1,683	4,559	2,488
Total	683	34,972	614	31,438	80,097	38,093
75% NET PROFITS INTERESTS						
Texas	1,553	720	458	213	7,714	3,854
Oklahoma	1,186	314	227	55	3,730	2,097
Total	2,739	1,034	685	268	11,444	5,951
TOTAL	3,422	36,006	1,299	31,706	$ 91,541	$ 44,044

[A] Based on year-end oil and gas prices. Discounted estimated future net revenues from proved reserves decreased 74% from year-end 2000 to 2001, primarily because of a 76% decrease in year-end gas prices over these periods. 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 (and the tax benefit of the estimated coal seam tax credit) since future net revenues are not subject to taxation at the trust level.

YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999

Net profits income for 2001 was $14,389,316, as compared with $11,660,510 for 2000 and $6,691,336 for 1999. The 23% increase in net profits income from 2000 to 2001 was because of higher product prices partially offset by higher development costs and increased production and property taxes associated with increased revenues. The 74% increase in net profits income from 1999 to 2000 was also because of higher product prices. During 2001, 2000 and 1999, 77%, 64% and 79%, respectively, of net profits income was derived from gas sales.

Trust administration expense was $198,482 in 2001 as compared to $185,624 in 2000 and $152,631 in 1999. Interest income was $19,050 in 2001, $27,228 in 2000 and $11,098 in 1999.

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 production and three months after 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

Oil. Underlying oil sales volumes increased 2% from 2000 to 2001, as compared to a 1% decrease from 1999 to 2000. Sales volume increases in 2001 were because of the timing of cash receipts partially offset by production decline. Sales volume decreases in 2000 were related to natural production decline and timing of cash receipts and were offset by increased production from properties underlying the Texas 75% and 90% net profits interests.

Gas. Underlying gas sales volumes decreased 5% from 2000 to 2001 as compared to a 15% decrease from 1999 to 2000. Lower 2001 gas sales volumes were primarily because of coal seam gas production decline. Lower 2000 gas sales volumes were primarily because of timing of cash receipts and coal seam gas production decline.

PRICES

Oil. The average oil price for 2001 was $24.99 per Bbl, 9% lower than the 2000 average oil price of $27.49, which was 85% higher than the 1999 average price of $14.88. After OPEC members and other oil producers agreed to production cuts in March 1999, oil prices climbed through the remainder of 1999 and first quarter 2000. Despite OPEC production increases in 2000, increased demand sustained higher prices. The West Texas Intermediate ("WTI") posted price reached $34.25 per Bbl in September 2000, its highest level in ten years. Lagging demand in 2001, resulting from a worldwide economic slowdown, caused oil prices to decline. OPEC members agreed to cut daily production by one million barrels in April and an additional one million barrels in September to adjust for weak demand and excess supply. The economic decline was accelerated by the terrorist attacks in the United States on September 11, 2001, placing additional downward pressure on oil prices. In December, OPEC announced additional production cuts of 1.5 million barrels per day effective January 1, 2002, for six months. The average WTI posted price for January and February 2002 was $17.06, compared with $22.87 for the year 2001 and $17.26 for fourth quarter 2001. Oil prices have risen in March to an average WTI posted price of about $21.00 through March 25. Recent trust oil prices have averaged approximately $0.70 higher than the WTI posted price.

Gas. The 2001 average gas price was $5.09 per Mcf, a 53% increase from the 2000 average gas price of $3.32, which was a 67% increase from the 1999 average price of $1.99. Gas prices were lower in 1999 primarily because of the abnormally warm winter of 1998-1999 across the United States that resulted in higher levels of gas storage. Gas prices began to increase in May 1999 and, after declining briefly at year end, strengthened in 2000, reaching a record high of $10.10 per MMBtu in December 2000 as winter demand strained gas supplies. Gas prices declined during 2001 because of fuel switching due to higher prices, milder weather and a weaker economy which has reduced the demand for gas and resulted in sharply increased gas storage levels. The average NYMEX price for January and February 2002 was $2.23 per MMBtu. Gas prices have risen in March to an average NYMEX posted price of $2.93 through March 25. The trust's recent gas prices have averaged $0.25 per MMBtu lower than the NYMEX price.

COSTS

Because properties underlying the 90% net profits interests are royalty and overriding royalty interests, the calculation of net profits income from these interests only includes deductions for production and property taxes, legal costs, and marketing and transportation charges. In addition to these costs, the calculation of net profits income from the 75% net profits interests includes deductions for production and development costs since the related underlying properties are working interests. Net profits income is calculated monthly for each of the five conveyances under which the net profits interests were conveyed to the trust. If monthly 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 other conveyances.

Continued on page 8

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]	
	2001	2000	1999	2001	2000
SALES VOLUMES					
Oil [BBLS] [B]					
Underlying properties	350,691	344,123	348,609	98,786	81,865
Average per day	961	940	955	1,074	890
Net profits interests	145,678	163,219	97,677	49,341	41,264
Gas [MCF] [B]					
Underlying properties	2,932,203	3,080,601	3,643,023	776,281	683,897
Average per day	8,033	8,417	9,981	8,438	7,434
Net profits interests	2,552,207	2,689,259	3,162,942	669,272	598,457
AVERAGE SALES PRICE					
Oil [PER BBL]	$ 24.99	$ 27.49	$ 14.88	$ 22.74	$ 31.18
Gas [PER MCF]	$ 5.09	$ 3.32	$ 1.99	$ 3.00	$ 4.33
REVENUES					
Oil sales	$ 8,763,283	$ 9,459,575	$ 5,189,030	$ 2,246,178	$ 2,552,251
Gas sales	14,922,881	10,231,063	7,260,100	2,329,339	2,959,679
Total Revenues	23,686,164	19,690,638	12,449,130	4,575,517	5,511,930
COSTS					
Taxes, transportation and other	3,298,631	2,566,816	1,606,058	691,398	640,856
Production expense [C]	2,908,305	2,520,954	2,390,818	731,502	658,350
Development costs	1,133,869	738,605	736,060	163,208	230,765
Excess costs	-	-	(432,789)	-	-
Recovery of excess costs and accrued interest	-	383,836	634,277	-	-
Total Costs	7,340,805	6,210,211	4,934,424	1,586,108	1,529,971
NET PROCEEDS	$ 16,345,359	$ 13,480,427	$ 7,514,706	$ 2,989,409	$ 3,981,959
NET PROFITS INCOME	$ 14,389,316	$ 11,660,510	$ 6,691,336	$ 2,609,358	$ 3,436,186

[A] Because of the interval between time of production and receipt of net profits income by the trust, oil and gas sales for the year ended December 31 generally relate to oil production from November through October and gas production from October through September, while oil and gas sales for the three months ended December 31 generally relate to oil production from August through October and gas production from July through September.

[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 analysis is based on the underlying properties.

[C] Includes an overhead fee deducted and retained by XTO Energy. As of December 31, 2001, this fee was $23,925 per month and is subject to adjustment each May based on an oil and gas industry index.

Before adjustment for excess costs (see "Excess Costs" below), total costs deducted in the calculation of net profits income were $7,340,805 in 2001, $5,826,375 in 2000 and $4,732,936 in 1999. The 26% increase in costs from 2000 to 2001 and the 23% increase in costs from 1999 to 2000 are primarily attributable to increased production and property tax and other purchaser deductions associated with higher revenues. In 2001, higher development costs are related to wells drilled on two of the underlying properties and increased production expense is related to the timing of maintenance projects and higher power and fuel costs.

EXCESS COSTS

At the beginning of 1999, accumulated excess costs and accrued interest for the Texas 75% net profits interests totaled $519,817. During 1999, costs exceeded revenues for properties underlying the Texas 75% net profits interests by $327,318 and for the properties underlying the Oklahoma 75% net profits interests by $105,471. Excess costs for the Texas 75% net profits interests were primarily the result of low oil prices and increased development costs for a 1998 carbon dioxide injection project, while excess costs for the Oklahoma 75% net profits interests were primarily because of low oil prices and reduced oil sales volumes related to mechanical complications on one of the underlying properties.

With improved oil prices, recoveries of excess costs and accrued interest totaled $911,223 for the Texas 75% net profits interests and $106,890 for the Oklahoma 75% net profits interests in the last half of 1999 and first half of 2000. Excess costs and accrued interest were fully recovered for the Texas 75% net profits interests in May 2000 and for the Oklahoma 75% net profits interests in October 1999. There were no excess costs in 2001.

In February and March 2002, total excess costs and accrued interest of $71,006 were incurred on the Texas 75% net profits interests as a result of lower oil prices and increased development costs. These costs must be recovered from the properties underlying the Texas 75% net profits interests before they can again contribute to trust net profits income.

See Note 5 to Financial Statements.

FOURTH QUARTER 2001 AND 2000

During the quarter ended December 31, 2001, the trust received net profits income totaling $2,609,358, compared with fourth quarter 2000 net profits income of $3,436,186. The 24% decrease in net profits income from fourth quarter 2000 to 2001 was primarily because of lower product prices.

Administration expense was $27,285 and interest income was $1,299, resulting in fourth quarter 2001 distributable income of $2,583,372, or $0.430562 per unit. Distributable income for fourth quarter 2000 was $3,430,356, or $0.571726 per unit. Distributions to unitholders for the quarter ended December 31, 2001 were:

RECORD DATE	PAYMENT DATE	PER UNIT
October 31, 2001	November 15, 2001	$ 0.137660
November 30, 2001	December 14, 2001	0.150764
December 31, 2001	January 15, 2002	0.142138
		$ 0.430562

VOLUMES

Fourth quarter 2001 underlying oil sales volumes were 98,786 Bbls, or 21% higher than 2000 levels. Underlying gas sales volumes were 776,281 Mcf, or 14% higher than 2000 levels. Volumes increased primarily because of the timing of cash receipts.

PRICES

The average fourth quarter 2001 oil price was $22.74 per Bbl, 27% lower than the fourth quarter 2000 average price of $31.18. The average fourth quarter gas price was $3.00 per Mcf in 2001, 31% lower than the fourth quarter 2000 average price of $4.33. For further information about oil and gas prices, see "Years Ended December 31, 2001, 2000 and 1999 – Prices" above.

COSTS

Costs deducted in the calculation of fourth quarter 2001 net profits income increased $56,137, or 4%, from fourth quarter 2000. This was the result of increased property tax partially offset by lower development costs primarily related to a carbon dioxide project on one of the properties underlying the Texas 75% net profits interests.

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.

	DECEMBER 31 2001	2000
ASSETS		
Cash and short-term investments	$ 852,349	$ 1,048,031
Interest to be received	479	3,307
Net profits interests in oil and gas properties – net (Notes 1 and 2)	28,895,086	30,755,456
	$ 29,747,914	$ 31,806,794
LIABILITIES AND TRUST CORPUS		
Distribution payable to unitholders	$ 852,828	$ 1,051,338
Trust corpus (6,000,000 units of beneficial interest authorized and outstanding)	28,895,086	30,755,456
	$ 29,747,914	$ 31,806,794

Statements of Distributable Income

	YEAR ENDED DECEMBER 31 2001	2000	1999
NET PROFITS INCOME	$ 14,389,316	$ 11,660,510	$ 6,691,336
Interest income	19,050	27,228	11,098
TOTAL INCOME	14,408,366	11,687,738	6,702,434
Administration expense	198,482	185,624	152,631
DISTRIBUTABLE INCOME	$ 14,209,884	$ 11,502,114	$ 6,549,803
Distribution income per unit (6,000,000 units)	$ 2.368314	$ 1.917019	$ 1.091635

Statements of Changes in Trust Corpus

	YEAR ENDED DECEMBER 31 2001	2000	1999
TRUST CORPUS – beginning of year	$ 30,755,456	$ 33,005,334	$ 36,024,941
Amortization of net profits interests	(1,860,370)	(2,249,878)	(3,019,607)
Distributable income	14,209,884	11,502,114	6,549,803
Distributions declared	(14,209,884)	(11,502,114)	(6,549,803)
TRUST CORPUS – end of year	$ 28,895,086	$ 30,755,456	$ 33,005,334

See Accompanying Notes to Financial Statements.

1. TRUST ORGANIZATION AND PROVISIONS

Cross Timbers Royalty Trust was created on February 12, 1991 by predecessors of XTO Energy Inc. (formerly known as Cross Timbers Oil Company), when the following net profits interests were conveyed under five separate conveyances to the trust effective October 1, 1990, in exchange for 6,000,000 units of beneficial interest in the trust:

- 90% net profits interests in certain producing and nonproducing royalty interest properties in Texas, Oklahoma and New Mexico, and
- 75% net profits interests in certain nonoperated working interest properties in Texas and Oklahoma.

The underlying properties from which the net profits interests were carved are currently owned by XTO Energy. Bank of America, N.A. is the trustee of the trust. The trust indenture provides, among other provisions, that:

- the trust may not engage in any business activity or acquire any assets other than the net profits interests and specific short-term cash investments;
- the trust may not dispose of all or part of the net profits interests unless approved by 80% of the unitholders, or upon trust termination, and 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 required to pay trust liabilities if fully repaid 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 revenue of the trust is less than $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).
- Interest income, interest to be received and distribution payable to unitholders include interest to be earned on net profits income from the monthly record date (last business day of the month) through the date of the next distribution.
- 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 certain contingencies that would not be recorded under generally accepted accounting principles.

The initial carrying value of the net profits interests of $61,100,449 was XTO Energy's historical net book value of the interests on February 12, 1991, 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 $32,205,363 as of December 31, 2001 and was $30,344,993 as of December 31, 2000.

3. DISTRIBUTIONS TO UNITHOLDERS

The trustee determines the amount to be distributed to unitholders each month by totaling net profits income and other cash receipts, and subtracting liabilities paid and adjustments in cash reserves established by the trustee. The resulting amount (with estimated interest to be received on such amount through the distribution date) is distributed to unitholders of record within ten business days after the monthly record date, 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 the net profits percentage of 90% or 75%. Net proceeds are the gross proceeds received from the sale of production, less applicable costs. For the 90% net profits interests, such costs generally include applicable taxes, transportation, legal and marketing charges, and do not include other production and development costs. For the 75% net profits interests, such costs include production costs, development and drilling costs, applicable taxes, operating charges and other costs.

XTO Energy, as owner of the underlying properties, computes net profits income separately for each of the five conveyances (Note 1). If costs exceed gross proceeds for any conveyance, such excess costs cannot be used to reduce the amounts to be received under the other conveyances. The trust is not liable for excess costs; however, future net profits income from the net profits interests created by that conveyance will be reduced by such excess costs plus accrued interest. See Note 5.

4. 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 trust 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 coal seam gas wells. Production through 2002 from coal seam gas wells drilled between December 31, 1979 and January 1, 1993 qualifies for the federal income tax credit for producing nonconventional fuels under Section 29 of the Internal Revenue Code. This tax credit was approximately $1.08 per MMBtu ($0.107183 per unit) in 2000 and $1.02 per MMBtu ($0.157564 per unit) in 1999. Such credit, 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 may be carried over indefinitely as a credit against the unitholder's regular tax liability, subject to the tentative minimum tax limitation.

Congress is considering an extension of existing energy tax credits beyond the scheduled December 31, 2002 expiration date, as well as the creation of similar new tax credits. During 2001, the U.S. House passed a bill that would extend existing Section 29 tax credits on certain production, while the U.S. Senate is considering a separate bill to address energy tax credits, including Section 29. The potential effect of any final legislation of unitholders is unknown.

XTO Energy has advised the trustee that costs exceeded revenues from the underlying properties of the 75% net profits interests during 1998 and 1999, which were recovered during 1999 and 2000. There were no excess costs or recoveries in 2001. Excess costs and accrued interest for each conveyance must be fully recovered from the respective future net proceeds of the 75% net profits interests before they can again contribute to trust net profits income. The following is a summary of changes in excess costs and recoveries by conveyance during 1999 and 2000.

	YEAR ENDED DECEMBER 31		
	2000 TEXAS	1999 TEXAS	1999 OKLAHOMA
Excess costs and accrued interest – beginning of period	$ 375,802	$ 519,817	$ -
Excess costs	-	327,318	105,471
Accrued interest	8,034	56,054	1,419
Recovery of excess costs and accrued interest	(383,836)	(527,387)	(106,890)
Excess costs and accrued interest – end of period	$ -	$ 375,802	$ -
Net to trust (75%)	$ -	$ 281,852	$ -

In February and March 2002, total excess costs and accrued interest of $71,006 were incurred on the Texas 75% net profits interests as a result of lower oil prices and increased development costs.

6. XTO ENERGY INC.

In computing net profits income for the 75% net profits interests (Note 3), XTO Energy deducts an overhead charge as reimbursement for costs associated with monitoring these interests. This charge at December 31, 2001 was $23,925 per month, or $287,100 annually (net to the trust of $17,944 per month or $215,325 annually), and is subject to annual adjustment based on an oil and gas industry index.

With the exception of working interests from which approximately 20 overriding royalty interests were conveyed, XTO Energy does not operate or control any of the underlying properties or related working interests. XTO Energy acquired these working interests after the overriding royalty interests were conveyed to the trust.

As of March 1, 2002, XTO Energy owned 22.7% of the outstanding trust units. In June 2001, the trust and XTO Energy filed an amended registration statement with the Securities and Exchange Commission to sell 1,360,000 units (22.7% of outstanding units) held by XTO Energy. The trust did not participate in XTO Energy's decisions to acquire or sell units and will not receive any of the proceeds in the event of such sale.

7. 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 which is included in this report.

8. QUARTERLY FINANCIAL DATA [UNAUDITED]

The following is a summary of net profits income, distributable income and distributable income per unit by quarter for 2001 and 2000:

	NET PROFITS INCOME	DISTRIBUTABLE INCOME	DISTRIBUTABLE INCOME PER UNIT
2001			
First Quarter	$ 4,107,459	$ 4,048,902	$ 0.674817
Second Quarter	4,221,331	4,178,970	0.696495
Third Quarter	3,451,168	3,398,640	0.566440
Fourth Quarter	2,609,358	2,583,372	0.430562
	$ 14,389,316	$ 14,209,884	$ 2.368314
2000			
First Quarter	$ 2,352,880	$ 2,300,796	$ 0.383466
Second Quarter	2,477,134	2,424,630	0.404105
Third Quarter	3,394,310	3,346,332	0.557722
Fourth Quarter	3,436,186	3,430,356	0.571726
	$ 11,660,510	$ 11,502,114	$ 1.917019

BANK OF AMERICA, N.A., AS TRUSTEE FOR THE CROSS TIMBERS ROYALTY TRUST:

We have audited the accompanying statements of assets, liabilities and trust corpus of the Cross Timbers Royalty Trust as of December 31, 2001 and 2000, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2001. 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 three years in the period ended December 31, 2001, 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

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, 2001 — Commission file number 1-10982

Cross Timbers Royalty Trust

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

Texas (State or other jurisdiction incorporation or of organization)	75-6415930 (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) 228-5084

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. ☒

At March 1, 2002, there were 6,000,000 units of beneficial interest of the trust outstanding. The aggregate market value of the units (based on the closing price on the New York Stock Exchange on March 1, 2002) held by non-affiliates of the registrant on that date was approximately $84.1 million.

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:

2001 Annual Report to Unitholders—Part II

PART I

Item 1. *Business*

Cross Timbers Royalty Trust is an express trust created under the laws of Texas pursuant to the Cross Timbers Royalty Trust Indenture entered into on February 12, 1991 between predecessors of XTO Energy Inc., as grantors, and NCNB Texas National Bank, as trustee. Bank of America, N.A., successor of NCNB Texas National Bank, is now the trustee of the trust. The principal office of the trust is located at 901 Main Street, Dallas, Texas 75202 (telephone number 877-228-5084).

On February 12, 1991, the predecessors of XTO Energy (formerly known as Cross Timbers Oil Company) conveyed defined net profits interests to the trust under five separate conveyances:

— one in each of the states of Texas, Oklahoma and New Mexico, to convey a 90% defined net profits interest carved out of substantially all royalty and overriding royalty interests owned by the predecessors in those states, and

— one in each of the states of Texas and Oklahoma, to convey a 75% defined net profits interest carved out of specific working interests owned by the predecessors in those states.

The conveyance of these net profits interests was effective for production from October 1, 1990. The net profits interests and the underlying properties are further described under Item 2.

In exchange for the conveyance of the net profits interests to the trust, the predecessors of XTO Energy received 6,000,000 units of beneficial interest of the trust. Predecessors of XTO Energy distributed units to their owners in February 1991 and November 1992, and in February 1992, sold units in the trust's initial public offering. Units are listed and traded on the New York Stock Exchange under the symbol "CRT." During 1996 and 1997, XTO Energy's Board of Directors authorized XTO Energy to purchase two million units. As of March 1, 2002, XTO Energy owned 1,360,000 units, or 22.7%, of the outstanding units.

In June 1998 the trust and XTO Energy filed a registration statement with the Securities and Exchange Commission to sell the 1,360,000 units held by XTO Energy. As XTO Energy stated in a related news release, the filing was made in anticipation of better commodity prices and any sale is dependent on an improved market for oil and gas equities. The registration statement was amended in October 2000 and June 2001. As of March 27, 2002, no sales have been made under the registration statement. The trust did not participate in XTO Energy's decisions to acquire or sell units and will not receive any of the proceeds in the event of such sale.

Under the terms of each of the five conveyances, the trust receives net profits income from the net profits interests on the last business day of each month. Net profits income is determined by XTO Energy by multiplying the net profit percentage (90% or 75%) times net proceeds from the underlying properties for each of the five conveyances during the previous month. Net proceeds are the gross proceeds received from the sale of production, less production costs. For the 90% net profits interests and the 75% net profits interests, "production costs" generally include applicable property taxes, transportation, marketing and other charges. For the 75% net profits interests only, production costs also include capital and operating costs paid (e.g., drilling, production and other direct costs of owning and operating the property) and a monthly overhead charge that is adjusted annually. The monthly overhead charge at December 31, 2001 was $23,925. If production costs exceed gross proceeds for any conveyance, such excess is carried forward to the computation of net proceeds for future months until the excess costs (plus interest accrued as specified in the conveyances) are completely recovered. Such excess production costs and related accrued interest from one conveyance cannot be used to reduce net proceeds from any other conveyance.

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.

With the exception of working interests from which approximately 20 overriding royalty interests in the San Juan Basin were conveyed, XTO Energy does not operate or control any of the underlying properties or related working interests. As a working interest owner, XTO Energy can generally decline participation in any operation and allow consenting parties to conduct such operations, as provided under the operating agreements. XTO Energy also can assign, sell, or otherwise transfer its interest in the underlying properties, subject to the net profits interests, or can abandon an underlying property that is a working interest if it is incapable of producing in paying quantities, as determined by XTO Energy.

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.

Net profits income received by the trust on or before the last business day of the month generally represents receipts attributable to oil production two months prior and gas production three months prior. The monthly distribution amount to unitholders is determined by:

Adding—

(1) net profits income received,

(2) estimated interest income to be received on the monthly distribution amount, including an adjustment for the difference between the estimated and actual interest received for the prior monthly distribution amount,

(3) cash available as a result of reduction of cash reserves, and

(4) any other cash receipts, and

Subtracting the sum of—

(1) liabilities paid and

(2) the reduction in cash available due 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 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 77% of the net profits income received by the trust during 2001, as well as 76% of the estimated proved reserves of the net profits interests at December 31, 2001 (based on estimated future net revenues 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 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 asset, with the exception of certain short-term investments as specified under Item 1. The trustee is prohibited from selling any portion of the net profits interests unless approved by at least 80% of the unitholders or at such time as trust gross revenue is less than $1,000,000 for two successive years.

The net profits interests are composed of:

—the 90% net profits interests which are carved from:

a) producing royalty and overriding royalty interest properties in Texas, Oklahoma and New Mexico, and

b) 11.11% non-participating royalty interests in nonproducing properties located primarily in Texas and Oklahoma;

—the 75% net profits interests which are carved from nonoperated working interests in four properties in Texas and three properties in Oklahoma.

All underlying royalties, underlying nonproducing royalties and underlying working interest properties are currently owned by XTO Energy. XTO Energy may sell all or any portion of the underlying properties at any time, subject to and burdened by the net profits interests.

Producing Acreage, Wells and Drilling

Underlying Royalties. The underlying royalties are royalty and overriding royalty interests primarily located in mature producing oil and gas fields. The most significant producing region in which the underlying royalties are located is the San Juan Basin in northwestern New Mexico. The trust's estimated proved reserves from this region totaled 26.1 Bcf at December 31, 2001, or approximately 82% of trust total gas reserves at that date. XTO Energy estimates that underlying royalties in the San Juan Basin include more than 2,000 gross (approximately 30 net) wells, covering over 60,000 gross acres. Most of these wells are operated by Amoco Production Company or Burlington Resources Oil & Gas Company. Production from conventional gas wells is primarily from the Dakota, Mesaverde and Pictured Cliffs formations.

Approximately 26% of trust 2001 gas sales volumes were from coal seam production in the San Juan Basin. Through the year 2002, sales of certain coal seam gas qualify for a federal income tax credit. See "Regulation—Coal Seam Tax Credit." Operators are seeking approval to increase the density of coal seam wells drilled in the San Juan Basin. XTO Energy anticipates that hearings on the request will be held in June 2002. Although XTO Energy believes that the outlook for approval of increased density drilling is good, there can be no assurance that such an increase will be approved.

Most of the trust's San Juan Basin conventional, or non-coal seam, production is from the Mesaverde formation. This formation has been approved for increased density drilling, doubling the number of drill wells allowed to four per spacing unit. XTO Energy has advised the trustee that it believes operators will further develop the Mesaverde formation underlying the net profits interests, and such future development could significantly impact underlying gas sales volumes. There was minimal drilling in 2001 because of environmental concerns that delayed the approval of drilling permits.

During 1996, additional eastward pipeline capacity was completed in the San Juan Basin, reducing the dependence of San Juan Basin gas on California markets and effectively increasing San Juan Basin gas prices in relation to prices from other regions. Gas-powered electricity generation continues to increase in the southwest U.S., thereby increasing demand for San Juan Basin gas. Additional eastward pipeline capacity for western Canadian gas supplies, which previously were primarily directed to U.S. West Coast markets, has also improved the market for San Juan Basin gas.

The underlying royalties also include royalties in the Sand Hills field of Crane County, Texas. Most of these properties are operated by ExxonMobil Corporation or Chevron, U.S.A. The Sand Hills field was discovered in 1931 and includes production from three main intervals, the Tubb, McKnight and Judkins. Development potential for the field includes recompletions and additional infill drilling.

The underlying royalties contain approximately 462,000 gross (approximately 26,000 net) producing acres. Well counts for the underlying royalties cannot be provided because information regarding the number of wells on royalty properties is generally not made available to royalty interest owners.

Underlying Working Interest Properties. The underlying working interest properties, detailed below, are developed properties undergoing secondary or tertiary recovery operations:

Unit	County/State	Operator	Ownership of XTO Energy Working Interest	Ownership of XTO Energy Revenue Interest
North Cowden	Ector/Texas	Occidental Permian, Ltd.	1.7%	1.4%
North Central Levelland	Hockley/Texas	ExxonMobil Corporation	3.2%	2.1%
Penwell	Ector/Texas	Texaco Exploration and Production, Inc.	5.2%	4.6%
Sharon Ridge Canyon	Borden/Texas	ExxonMobil Corporation	4.3%	2.8%
Hewitt	Carter/Oklahoma	ExxonMobil Corporation	11.3%	9.9%
Wildcat Jim Penn	Carter/Oklahoma	LeNorman Partners, L.L.C.	8.6%	7.5%
South Graham Deese	Carter/Oklahoma	Maynard Oil Company	8.2%	7.0%

The underlying working interest properties consist of 60,154 gross (2,290 net) producing acres. As of December 31, 2001, there were 1,525 gross (70.0 net) productive oil wells, 1,015 gross (43.4 net) injection wells and two wells in process of drilling on these properties. During 2001, 50 gross (1.4 net) wells were drilled, during 2000, 12 gross (0.2 net) wells were drilled and during 1999, eight gross (0.1 net) wells were drilled. Nine gross (0.2 net) wells drilled in 2001 were water injections wells.

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 oil production and three months after gas 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, 2001 were as follows:

Production	90% Net Profits Interests 2001	2000	1999	75% Net Profits Interests 2001	2000	1999	Total 2001	2000	1999
Underlying Properties									
Oil—Sales (Bbls)	92,329	86,970	92,650	258,362	257,153	255,959	350,691	344,123	348,609
Average per day (Bbls)	253	238	254	708	702	701	961	940	955
Gas—Sales (Mcf)	2,845,132	2,964,687	3,548,594	87,071	115,914	94,429	2,932,203	3,080,601	3,643,023
Average per day (Mcf)	7,795	8,100	9,722	238	317	259	8,033	8,417	9,981
Net Profits Interests									
Oil—Sales (Bbls)	82,745	76,959	77,783	62,933	86,260	19,894	145,678	163,219	97,677
Average per day (Bbls)	227	210	213	172	236	55	399	446	268
Gas—Sales (Mcf)	2,530,916	2,659,139	3,152,693	21,291	30,120	10,249	2,552,207	2,689,259	3,162,942
Average per day (Mcf)	6,934	7,266	8,638	58	82	28	6,992	7,348	8,666
Average Sales Price									
Oil (per Bbl)	$24.22	$26.41	$14.54	$25.26	$27.85	$15.01	$24.99	$27.49	$14.88
Gas (per Mcf)	$ 5.14	$ 3.36	$ 2.01	$ 3.31	$ 2.28	$ 1.35	$ 5.09	$ 3.32	$ 1.99

Nonproducing Acreage

The underlying nonproducing royalties contain approximately 200,000 gross (approximately 3,000 net) acres in Texas, Oklahoma and New Mexico which were nonproducing at the date of the trust's creation. XTO Energy is the owner of underlying mineral interests in the majority of this acreage. The trust is entitled to 10% of oil and gas production attributable to the underlying mineral properties, but is not entitled to delay rental payments or lease bonuses. There has been no significant development of such nonproducing acreage since the trust's creation.

Pricing and Sales Information

Oil and gas are generally sold from the underlying properties at market-sensitive prices. The majority of sales from the underlying working interest properties are to major oil and gas companies. Information about purchasers of oil and gas from royalty properties is generally not provided by operators to XTO Energy as a royalty owner, or to the trust.

Oil and Natural Gas Reserves

General

Miller and Lents, Ltd., independent petroleum engineers, has estimated oil and gas reserves attributable to the underlying properties and net profits interests as of December 31, 2001, 2000, 1999 and 1998. 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 75% net profits interests in the working interest properties have effectively been reduced to reflect recovery of the trust's 75% portion of applicable production and development costs. Because trust reserve quantities are determined using an allocation formula, any fluctuations in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the net profits interests.

The standardized measure of discounted future net cash flows and changes in such discounted cash flows as presented below are prepared using assumptions required by the Financial Accounting Standards Board. Such 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 revenues are not subject to taxation at the trust level.

Year-end oil prices used to determine the standardized measure were based on a West Texas Intermediate crude oil posted price of $16.75 per Bbl in 2001, $23.75 per Bbl in 2000, $22.75 per Bbl in 1999 and $9.50 per Bbl in 1998. The year-end weighted average realized gas prices used to determine the standardized measure were $2.28 per Mcf in 2001, $9.48 per Mcf in 2000, $2.19 per Mcf in 1999 and $1.88 per Mcf in 1998.

Proved Reserves

(in thousands)	Net Profits Interests						Underlying Properties	
	90% Net Profits Interests		75% Net Profits Interests		Total			
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
Balance, December 31, 1998	676.5	36,453.2	247.1	65.3	923.6	36,518.5	2,409.9	41,733.4
Extensions, discoveries and other additions	10.5	162.2	-0-	-0-	10.5	162.2	13.1	186.0
Revisions of prior estimates	109.9	1,462.1	1,251.8	533.4	1,361.7	1,995.5	2,385.7	2,322.0
Production	(77.8)	(3,152.7)	(19.9)	(10.2)	(97.7)	(3,162.9)	(348.6)	(3,643.0)
Balance, December 31, 1999	719.1	34,924.8	1,479.0	588.5	2,198.1	35,513.3	4,460.1	40,598.4
Extensions, discoveries and other additions	3.2	77.1	-0-	-0-	3.2	77.1	3.5	85.7
Revisions of prior estimates	32.7	1,864.4	33.2	14.0	65.9	1,878.4	123.5	1,773.5
Production	(77.0)	(2,659.1)	(86.2)	(30.1)	(163.2)	(2,689.2)	(344.1)	(3,080.6)
Balance, December 31, 2000	678.0	34,207.2	1,426.0	572.4	2,104.0	34,779.6	4,243.0	39,377.0
Extensions, discoveries and other additions	12.3	247.8	-0-	-0-	12.3	247.8	13.7	274.8
Revisions of prior estimates	6.9	(486.5)	(678.2)	(282.9)	(671.3)	(769.4)	(483.6)	(713.2)
Production	(82.8)	(2,530.9)	(62.9)	(21.3)	(145.7)	(2,552.2)	(350.7)	(2,932.2)
Balance, December 31, 2001	614.4	31,437.6	684.9	268.2	1,299.3	31,705.8	3,422.4	36,006.4

Revisions of prior estimates of the 75% net profits interests' proved reserves and the underlying properties' proved oil reserves in each of the years above were primarily the result of changes in the year-end oil prices used in estimating proved reserves. During 2000 and 1999, upward revisions of the 90% net profits interests' proved gas reserves were primarily because of lower than anticipated production declines. Downward revisions of the 90% net profits interests in 2001 were primarily because of significantly lower year-end prices. Higher upward and downward revisions for the net profits interests as compared to underlying properties in 2001 and 2000 were caused by year-end price fluctuations which resulted in increased gas reserves allocated to or from the trust. See "General" above.

Proved Developed Reserves

(in thousands)	Net Profits Interests						Underlying Properties	
	90% Net Profits Interests		75% Net Profits Interests		Total			
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
December 31, 1998	672.8	34,514.0	206.4	60.7	879.2	34,574.7	2,195.1	39,520.1
December 31, 1999	715.7	33,036.5	1,375.0	570.3	2,090.7	33,606.8	4,245.6	38,463.3
December 31, 2000	675.0	32,371.1	1,317.8	553.5	1,992.8	32,924.6	4,028.8	37,300.0
December 31, 2001	611.4	29,608.5	602.0	253.7	1,213.4	29,862.2	3,208.3	33,937.3

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)	90% Net Profits Interests			75% Net Profits Interests			Total		
	December 31,			December 31,			December 31,		
	2001	2000	1999	2001	2000	1999	2001	2000	1999
Net Profits Interests									
Future cash inflows	$ 87,042	$ 347,874	$ 97,902	$12,275	$ 40,146	$ 36,670	$ 99,317	$388,020	$134,572
Future production taxes	(6,945)	(28,042)	(7,751)	(831)	(2,786)	(2,487)	(7,776)	(30,828)	(10,238)
Future net cash flows	80,097	319,832	90,151	11,444	37,360	34,183	91,541	357,192	124,334
10% discount factor	(42,004)	(169,073)	(46,573)	(5,493)	(18,692)	(17,135)	(47,497)	(187,765)	(63,708)
Standardized measure	$ 38,093	$ 150,759	$ 43,578	$ 5,951	$ 18,668	$ 17,048	$ 44,044	$169,427	$ 60,626

	2001	2000	1999
Underlying Properties			
Future cash inflows	$145,759	$484,675	$200,075
Future costs:			
Production	(40,984)	(78,973)	(52,858)
Development	(520)	(520)	(517)
Future net cash flows	104,255	405,182	146,700
10% discount factor	(53,994)	(212,781)	(74,879)
Standardized measure	$ 50,261	$192,401	$ 71,821

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

(in thousands)	90% Net Profits Interests			75% Net Profits Interests			Total		
	2001	2000	1999	2001	2000	1999	2001	2000	1999
Net Profits Interests									
Standardized measure, January 1	$ 150,759	$ 43,578	$34,584	$ 18,668	$17,048	$ 1,192	$ 169,427	$ 60,626	$35,776
Extensions, discoveries and other additions	507	461	384	-0-	-0-	-0-	507	461	384
Accretion of discount	12,702	3,683	3,078	1,614	1,476	106	14,316	5,159	3,184
Revisions of prior estimates, changes in price and other	(113,093)	112,338	11,864	(12,724)	2,504	16,109	(125,817)	114,842	27,973
Net profits income	(12,782)	(9,301)	(6,332)	(1,607)	(2,360)	(359)	(14,389)	(11,661)	(6,691)
Standardized measure, December 31	$ 38,093	$150,759	$43,578	$ 5,951	$18,668	$17,048	$ 44,044	$169,427	$60,626

	2001	2000	1999
Underlying Properties			
Standardized measure, January 1	$ 192,401	$ 71,821	$40,593
Revisions:			
Prices and costs	(140,000)	122,144	12,549
Quantity estimates	(1,581)	7,162	22,311
Accretion of discount	16,265	6,060	3,561
Future development costs	(1,091)	(738)	(697)
Other	49	(1,079)	591
Net revisions	(126,358)	133,549	38,315
Extensions, additions and discoveries	563	512	427
Production	(17,479)	(14,220)	(8,250)
Development costs	1,134	739	736
Net change	(142,140)	120,580	31,228
Standardized measure, December 31	$ 50,261	$192,401	$71,821

Discounted Present Value of the Coal Seam Tax Credit

The standardized measure above does not include the effects of the coal seam tax credit since the trust is not a taxable entity. The following table summarizes the estimated coal seam tax credit attributable to the 90% net profits interests at December 31, 2001, 2000 and 1999. Such estimates are based on projected coal seam gas production through the year 2002 (after which date the tax credit may no longer be available) as estimated by independent engineers. The estimates are also based on the current year estimated Btu content and the coal seam tax credit of $1.08 per MMBtu at December 31, 2001, $1.06 per MMBtu at December 31, 2000 and $1.02 per MMBtu at December 31, 1999. See "Regulation—Coal Seam Tax Credit."

(in thousands)	December 31,		
	2001	2000	1999
Undiscounted	$ 922	$1,225	$1,979
Discounted present value at 10%	$ 880	$1,120	$1,740

Reversion Agreement

Certain of the underlying royalties are subject to a reversion agreement between XTO Energy and a third party. The agreement calls for XTO Energy to transfer 25% of its interest in those properties to the third party when amounts received by XTO Energy from the underlying properties subject to the agreement equal the purchase price of the properties plus a 1% per month return on the unrecouped purchase price, known as payout. If payout were to occur and the 25% interest were to be transferred to the third party, the amounts payable to the trust would be proportionately reduced. Based on 2001 prices and levels of production, XTO Energy has advised the trustee that payout is not projected to occur for approximately 20 years. Unless higher prices and production are sustained for several years, this reversion agreement is not expected to have a material impact on the trust.

Regulation

Natural Gas Regulation

The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation rates charged and various other matters, by the Federal Energy Regulatory Commission (FERC). 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 by Congress or the various state legislatures, and what effect, if any, such proposals might have on the operations of the underlying properties.

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.

Coal Seam Tax Credit

The trust receives net profits income from coal seam gas wells. Under Section 29 of the Internal Revenue Code, coal seam gas produced through the year 2002 from wells drilled after December 31, 1979 and prior to January 1, 1993 qualifies for the federal income tax credit for producing nonconventional fuels. This tax credit for 2001 was approximately $1.08 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 is considering an extension of existing energy tax credits beyond the scheduled December 31, 2002 expiration date, as well as the creation of similar new tax credits. During 2001, the U.S. House passed a bill that would extend existing Section 29 tax credits on certain production, while the U.S. Senate is considering a separate bill to address energy tax credits, including Section 29. The potential effect of any final legislation on unitholders is unknown.

In 1999, a U.S. Court of Appeals held that a well drilled and completed in an otherwise qualifying formation prior to January 1, 1993 is not eligible for the Section 29 credit unless the producer received an appropriate well category determination from the FERC. The decision indicated that lack of a well category determination may render the Section 29 credit unavailable with respect to production from wells recompleted in a qualified formation after January 1, 1993, the date that the FERC's authority to render category determinations ended. Effective September 2000, the FERC amended its regulations to reinstate certain regulations to allow it to provide well category determinations for Section 29 tax credits for well recompletions commenced after January 1, 1993.

Other Regulation

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

Item 3. *Legal Proceedings*

Certain of the trust properties are involved in various 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 2001.

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, 2001 is incorporated herein by reference.

Item 6. *Selected Financial Data*

	Year Ended Decxember 31,				
	2001	2000	1999	1998	1997
Net Profits Income	$14,389,316	$11,660,510	$ 6,691,336	$ 7,079,632	$10,549,668
Distributable Income	14,209,884	11,502,114	6,549,803	6,927,338	10,407,250
Distributable Income per Unit	2.368314	1.917019	1.091635	1.154555	1.734541
Distributions per Unit	2.368314	1.917019	1.091635	1.154555	1.734541
Total Assets at Year-End	29,747,914	31,806,794	33,919,338	36,554,480	38,767,918

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, 2001 on pages 6 through 8 of the trust's annual report to unitholders for the year ended December 31, 2001 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 may borrow funds required to pay trust liabilities if fully repaid prior to further distributions to unitholders.

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

Contractual Obligations and Commitments

The trust had no obligations and commitments to make future contractual payments as of December 31, 2001, other than the December distribution payable to unitholders in January 2002, 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.

Related Party Transactions

The underlying properties are currently owned by XTO Energy. As of March 1, 2002, XTO Energy owned 1,360,000, or 22.7%, of the 6,000,000 outstanding units. XTO Energy deducts an overhead charge from monthly net proceeds as reimbursement for costs associated with monitoring the 75% net profits interests. As of December 31, 2001, this monthly charge was $23,925 ($17,944 net to the trust) and is subject to annual adjustment based on an oil and gas industry index. For further information regarding the trust's relationship with XTO Energy, see Note 6 to Financial Statements in the accompanying annual report.

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 accompanying annual report.

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. 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 of the trust's Annual Report on Form 10-K, 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. Any number of factors could cause actual results to differ materially, including, but not limited to, crude oil and natural gas price fluctuations, changes in the underlying demand for oil and natural gas, changes in ownership and/or the operator of the underlying properties, the timing and results of development activity, the availability of drilling equipment, as well as general domestic and international economic and political conditions.

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

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

Item 8. *Financial Statements and Supplementary Data*

The financial statements of the trust and the notes thereto, together with the related report of Arthur Andersen LLP dated March 19, 2002, appearing on pages 9 through 12 of the trust's annual report to unitholders for the year ended December 31, 2001 are incorporated herein by reference.

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

There have been no changes in accountants or disagreements with accountants on any matter of accounting principles or practices or financial statement disclosures during the two years ended December 31, 2001.

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.

Item 11. *Executive Compensation*

The trustee received the following annual compensation from 1999 through 2001 as specified in the trust indenture:

Name and Principal Position	Year	Other Annual Compensation (1)
Bank of America, N.A., Trustee	2001	$7,195
	2000	5,830
	1999	3,346

(1) Under the trust indenture, the trustee is entitled to an administrative fee of: (i) 1/20 of 1% of the first $100 million of the annual gross revenue of the trust, and 1/30 of 1% of the annual gross revenue of the trust in excess of $100 million, and (ii) trustee's standard hourly rates for time in excess of 300 hours annually.

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

(a) *Security Ownership of Certain Beneficial Owners.* The following table sets forth as of March 1, 2002 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, TX 76102	1,360,000 units (1)	22.7%

(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 January 31, 2002, Bank of America, N.A. owned, in various fiduciary capacities, 71,625 units with a shared right to vote 11,287 of these units and no right to vote 60,338 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 75% net profits interests, XTO Energy deducts an overhead charge as reimbursement for costs associated with monitoring these interests. This charge at December 31, 2001 was $23,925 per month, or $287,100 annually (net to the trust of $17,944 per month or $215,325 annually), and is subject to annual adjustment based on an oil and gas industry index.

During 2001, Bank of America, N.A. received $938 for oil and gas consulting services performed on behalf of the trust. See Item 11 for the remuneration received by the trustee from 1999 through 2001 and Item 12(b) for information concerning units owned by the trustee, Bank of America, N.A., in various fiduciary capacities.

PART IV

Item 14. *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)*

   Report of Independent Public Accountants
   Statements of Assets, Liabilities and Trust Corpus at December 31, 2001 and 2000
   Statements of Distributable Income for the years ended December 31, 2001, 2000 and 1999
   Statements of Changes in Trust Corpus for the years ended December 31, 2001, 2000 and 1999
   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) Cross Timbers Royalty Trust Indenture amended and restated on January 13, 1992 by NationsBank, N.A. (now Bank of America, N.A.), as trustee, heretofore filed as Exhibit 3.1 to the trust's Registration Statement No. 33-44385 filed with the Securities and Exchange Commission on February 19, 1992, is incorporated herein by reference.

   (b) Net Overriding Royalty Conveyance (Cross Timbers Royalty Trust, 90%—Texas) from South Timbers Limited Partnership, West Timbers Limited Partnership, North Timbers Limited Partnership, East Timbers Limited Partnership, Hickory Timbers Limited Partnership, and Cross Timbers Partners, L.P. (predecessors of Cross Timbers Oil Company, L.P.) to NCNB Texas National Bank (now Bank of America, N.A.), as trustee, dated February 12, 1991 (without Schedules A and B), heretofore filed as Exhibit 10.1 to the trust's Registration Statement No. 33-44385 filed with the Securities and Exchange Commission on February 19, 1992, is incorporated herein by reference.

   (c) Correction to Net Overriding Royalty Conveyance (Cross Timbers Royalty Trust, 90%—Texas) from South Timbers Limited Partnership, West Timbers Limited Partnership, North Timbers Limited Partnership, East Timbers Limited Partnership, Hickory Timbers Limited Partnership, and Cross Timbers Partners, L.P. (predecessors of Cross Timbers Oil Company, L.P.) to NCNB Texas National Bank (now Bank of America, N.A.), as trustee, dated September 23, 1991 (without Schedules A and B), heretofore filed as Exhibit 10.2 to the trust's Registration Statement No. 33-44385 filed with the Securities and Exchange Commission on February 19, 1992, is incorporated herein by reference.

   (d) Net Overriding Royalty Conveyance (Cross Timbers Royalty Trust, 75%—Texas) from South Timbers Limited Partnership, West Timbers Limited Partnership, North Timbers Limited Partnership, East Timbers Limited Partnership, Hickory Timbers Limited Partnership, and Cross Timbers Partners, L.P. (predecessors of Cross Timbers Oil Company, L.P.) to NCNB Texas National Bank (now Bank of America, N.A.), as trustee, dated February 12, 1991 (without Schedules A and B), heretofore filed as Exhibit 10.5 to the trust's Registration Statement No. 33-44385 filed with the Securities and Exchange Commission on February 19, 1992, is incorporated herein by reference.

   (13) Cross Timbers Royalty Trust annual report to unitholders for the year ended December 31, 2001

   (23.1) Consent of Arthur Andersen LLP

   (23.2) Consent of Miller and Lents, Ltd.

(99.1) Assurance Letter Regarding Arthur Andersen LLP

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, 2001, 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.

CROSS TIMBERS ROYALTY TRUST
By BANK OF AMERICA, N.A., TRUSTEE

By RON E. HOOPER
Ron E. Hooper
Senior Vice President

XTO ENERGY INC.

Date: March 27, 2002

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

(The trust has no directors or executive officers.)

901 Main Street, 17th Floor
P.O. Box 830650
Dallas, Texas 75283-0650
(877) 228-5084
Bank of America, N.A., Trustee

A copy of the Cross Timbers 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.

AUDITORS
Arthur Andersen LLP
Fort Worth, Texas

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

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

TRANSFER AGENT AND REGISTRAR
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CROSS TIMBERS ROYALTY TRUST

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