2003

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

Form 10-K

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

For the fiscal year ended **December 31, 2003**

OR

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

For the transition period from ___________ to ___________

Commission File Number: 1-10662

XTO Energy Inc.

(Exact name of registrant as specified in its charter)

Delaware	75-2347769	810 Houston Street, Fort Worth, Texas	76102
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (817) 870-2800

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 par value, including preferred stock purchase rights	New York Stock Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes_X_ No___

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

Indicate by checkmark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).
Yes_X_ No ___

Aggregate market value of the Common Stock based on the closing price on the New York Stock Exchange as of June 30, 2003 (the last business day of its most recently completed second fiscal quarter), held by nonaffiliates of the Registrant on that date was approximately $3.5 billion.

Number of Shares of Common Stock outstanding as of March 8, 2004 (as adjusted for the 5-for-4 stock split to be effected March 17, 2004) - 234,838,221

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Part III of this Report is incorporated by reference from the Registrant's definitive Proxy Statement for its Annual Meeting of Stockholders, which will be filed with the Commission no later than April 30, 2004.

XTO ENERGY INC.
2003 ANNUAL REPORT ON FORM 10-K
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PART I

Items 1. and 2. *BUSINESS AND PROPERTIES*

General

XTO Energy Inc. and its subsidiaries ("the Company" or "XTO") are engaged in the acquisition, development, exploitation and exploration of producing oil and gas properties, and in the production, processing, marketing and transportation of oil and natural gas. The Company was formerly known as Cross Timbers Oil Company and changed its name to XTO Energy Inc. in June 2001.

Our corporate internet web site is www.xtoenergy.com. We make available free of charge, on or through the investor relations section of our web site, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

We have grown primarily through acquisitions of proved oil and gas reserves, followed by development and exploitation activities and strategic acquisitions of additional interests in or near such acquired properties. Growth for the next year or more is expected to be accomplished through a combination of acquisitions and development. Given expected significant property divestitures by major energy, merchant energy, power generating and utility companies, larger strategic acquisitions could be made during 2004.

Our corporate headquarters are located in Fort Worth, Texas at 810 Houston Street (telephone 817-870-2800). Our proved reserves are principally located in relatively long-lived fields with well-established production histories concentrated in the following areas:

- the Eastern Region, located in East Texas and North Louisiana;
- the San Juan and Raton Basins of northern New Mexico and southern Colorado;
- the Arkoma Basin of Arkansas and Oklahoma;
- the Hugoton Field of Oklahoma and Kansas;
- the Anadarko Basin of Oklahoma;
- the Green River Basin of Wyoming;
- the Permian Basin of West Texas and southeastern New Mexico; and
- the Middle Ground Shoal Field of Alaska's Cook Inlet.

We use the following volume abbreviations throughout this Form 10-K. "Equivalent" volumes are computed with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

- Bbl — Barrel (of oil or natural gas liquids)
- Bcf — Billion cubic feet (of natural gas)
- Bcfe — Billion cubic feet equivalent
- Mcf — Thousand cubic feet (of natural gas)
- Mcfe — Thousand cubic feet equivalent
- MMBtu — One million British Thermal Units, a common energy measurement
- Tcf — Trillion cubic feet (of natural gas)
- Tcfe — Trillion cubic feet equivalent

Our estimated proved reserves at December 31, 2003 were 3.6 Tcf of natural gas, 34.7 million Bbls of natural gas liquids and 55.4 million Bbls of oil, based on December 31, 2003 prices of $5.71 per Mcf for gas, $23.17 per Bbl for natural gas liquids and $30.55 per Bbl for oil. Approximately 74% of December 31, 2003 proved reserves, computed on an Mcfe basis, were proved developed reserves. Increased proved reserves during 2003 were primarily the result of acquisitions and development and exploitation activities. During 2003, our daily average production was 668,436 Mcf of gas, 6,463 Bbls of natural gas liquids and 12,943 Bbls of oil. Fourth quarter 2003 daily average production was 738,053 Mcf of gas, 6,528 Bbls of natural gas liquids and 12,850 Bbls of oil.

Our properties have relatively long reserve lives and highly predictable production profiles. Based on December 31, 2003 proved reserves and projected 2004 production from properties owned as of December 31, 2003, the average reserve-to-production index of our proved reserves is 14.7 years. In general, these properties have extensive production histories and production enhancement opportunities. While the properties are geographically diversified, the major producing fields are concentrated within core areas, allowing for substantial economies of scale in production and cost-effective application of reservoir management techniques gained from prior operations. As of December 31, 2003, we owned interests in 11,364 gross (5,633.6 net) wells, and we operated wells representing 92.2% of the present value of cash flows before income taxes (discounted at 10%) from estimated proved reserves. The high proportion of operated properties allows us to exercise more control over expenses, capital allocation and the timing of development and exploitation activities in our fields.

We have generated a substantial inventory of approximately 2,700 potential development drilling locations. Drilling plans are primarily dependent upon product prices and the availability and pricing of drilling equipment and supplies.

We employ a disciplined acquisition program refined by senior management to augment our core properties and expand our reserve base. Our engineers and geologists use their expertise and experience gained through the management of existing core properties to target properties to be acquired with similar geological and reservoir characteristics.

We operate gas gathering systems in several of our core producing areas. We also operate gas processing plants in East Texas, the Hugoton Field and the Cotton Valley Field of Louisiana. Gas gathering and processing operations are only in areas where we have production and are considered activities which add value to our natural gas production and sales operations.

We market our gas production and the gas output of our gathering and processing systems. A large portion of our natural gas is processed and the resultant natural gas liquids are marketed by unaffiliated third parties. We use fixed price physical sales contracts and futures, forward sales contracts and other price risk management instruments to hedge pricing risks.

History of the Company

The Company was incorporated in Delaware in 1990 to ultimately acquire the business and properties of predecessor entities that were created from 1986 through 1989. Our initial public offering of common stock was completed in May 1993.

During 1991, we formed Cross Timbers Royalty Trust by conveying a 90% net profits interest in substantially all of the royalty and overriding royalty interests that we then owned in Texas, New Mexico and Oklahoma, and a 75% net profits interest in seven nonoperated working interest properties in Texas and Oklahoma. Cross Timbers Royalty Trust units are listed on the New York Stock Exchange under the symbol "CRT." From 1996 to 1998, we purchased 1,360,000, or 22.7%, of the outstanding units, at a total cost of $18.7 million. In August 2003, our Board of Directors declared a dividend of 0.0059 units of the trust for each share of our common stock outstanding on September 2, 2003, after adjustment for the five-for-four stock split to be effected on March 17, 2004. This dividend, totaling 1,360,000 trust units, was distributed on September 18, 2003, after which we no longer own any Cross Timbers Royalty Trust units.

In December 1998, we formed the Hugoton Royalty Trust by conveying an 80% net profits interest in principally gas-producing operated working interests in the Hugoton area of Kansas and Oklahoma, the Anadarko Basin of Oklahoma and the Green River Basin of Wyoming. These net profits interests were conveyed to the trust in exchange for 40 million units of beneficial interest. We sold 17 million units in the trust's initial public offering in 1999 and 1.3 million units pursuant to an employee incentive plan in 1999 and 2000. We own the remaining 54% of the units, which we account for as producing properties. Hugoton Royalty Trust units are listed on the New York Stock Exchange under the symbol "HGT."

Industry Operating Environment

The oil and gas industry is affected by many factors that we generally cannot control. Governmental regulations, particularly in the areas of taxation, energy and the environment, can have a significant impact on operations and profitability. Crude oil prices are determined by global supply and demand. Oil supply is significantly influenced by production levels of OPEC member countries, while demand is largely driven by the condition of worldwide economies, as well as weather. Our natural gas prices are generally determined by North American supply and demand. Weather has a significant impact on demand for natural gas since it is a primary heating resource. Its increased use for electrical generation has kept natural gas demand elevated throughout the year, removing some of the seasonal swing in prices. See "Significant Events, Transactions and Conditions – Product Prices" in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," regarding recent price fluctuations and their effect on our results.

Business Strategy

The primary components of our business strategy are:

- acquiring long-lived, operated oil and gas properties, including undeveloped leases,
- increasing production and reserves through aggressive management of operations and through development, exploitation and exploration activities,
- hedging a portion of our production to stabilize cash flow and protect the economic return on development projects, and
- retaining management and technical staff that have substantial experience in our core areas.

Acquiring Long-Lived, Operated Properties. We seek to acquire long-lived, operated producing properties that:

- contain complex multiple-producing horizons with the potential for increases in reserves and production,
- produce from non-conventional sources, including tight natural gas reservoirs, coal bed methane and natural gas-producing shale formations,
- are in core operating areas or in areas with similar geologic and reservoir characteristics, and
- present opportunities to reduce expenses per Mcfe through more efficient operations.

We believe that the properties we acquire provide opportunities to increase production and reserves through the implementation of mechanical and operational improvements, workovers, behind-pipe completions, secondary recovery operations, new development wells and other development activities. We also seek to acquire facilities related to gathering, processing, marketing and transporting oil and gas in areas where we own reserves. Such facilities can enhance profitability, reduce costs, and provide marketing flexibility and access to additional markets. The ability to successfully purchase properties is dependent upon, among other things, competition for such purchases and the availability of financing to supplement internally generated cash flow.

We also seek to acquire undeveloped properties that potentially have the same attributes as targeted producing properties.

Increasing Production and Reserves. A principal component of our strategy is to increase production and reserves through aggressive management of operations and low-risk development. We believe that our principal properties possess geologic and reservoir characteristics that make them well suited for production increases through drilling and other development programs. We have generated an inventory of approximately 2,700 potential drilling locations. Additionally, we review operations and mechanical data on operated properties to determine if actions can be taken to reduce operating costs or increase production. Such actions include installing, repairing and upgrading lifting equipment, redesigning downhole equipment to improve production from different zones, modifying gathering and other surface facilities and conducting restimulations and recompletions. We may also initiate, upgrade or revise existing secondary recovery operations.

Exploration Activities. During 2004, we plan to focus our exploration activities on projects that are near currently owned productive fields. We believe that we can prudently and successfully add growth potential through exploratory activities given improved technology, our experienced technical staff and our expanded base of operations. We have allocated approximately $25 million of our $520 million 2004 development budget for exploration activities.

Hedging Activities. We enter futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts. Our policy is to routinely hedge a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the benefit of rising prices, management plans to continue its hedging strategy because of the benefits provided by predictable, stable cash flow, including:

– Ability to more efficiently plan and execute our development program, which facilitates predictable production growth,

– Ability to enter long-term arrangements with drilling contractors, allowing us to continue development projects when product prices decline,

– More consistent returns on investment, and

– Better utilization of our personnel.

Experienced Management and Technical Staff. Most senior management and technical staff have worked together for over 20 years and have substantial experience in our core operating areas. Bob R. Simpson and Steffen E. Palko, co-founders of the Company, were previously executive officers of Southland Royalty Company, one of the largest U.S. independent oil and gas producers prior to its acquisition by Burlington Northern, Inc. in 1985.

Other Strategies. We may also acquire working interests in nonoperated producing properties if such interests otherwise meet our acquisition criteria. We attempt to acquire nonoperated interests in fields where the operators have a significant interest to protect, including potential undeveloped reserves that will be exploited by the operator. We may also acquire nonoperated interests in order to ultimately accumulate sufficient ownership interests to operate the properties.

We also attempt to acquire a portion of our reserves as royalty interests. Royalty interests have few operational liabilities because they do not participate in operating activities and do not bear production or development costs.

Royalty Trusts and Publicly Traded Partnerships. We have created and sold units in publicly traded royalty trusts. Sales of royalty trust units allow us to more efficiently capitalize our mature, lower-growth properties. We may create and distribute or sell interests in additional royalty trusts or publicly traded partnerships in the future.

Business Goals. In January 2004, we announced a strategic goal for 2004 of increasing gas production by 16% to 18% over 2003 levels. With the announcement of additional acquisitions in February 2004, we updated our goal to increase gas production by 18% to 20% over 2003 levels. To achieve this growth target, we plan to drill about 420 (336 net) development wells and perform approximately 350 (251 net) workovers and recompletions in 2004.

We have budgeted $1.17 billion for our 2004 development and acquisition programs, which is expected to be substantially funded by cash flow from operations. We plan to allocate $650 million of the 2004 capital budget to acquisitions, including $243 million of acquisitions in January 2004 and $200 million expected to close in April 2004 (see Note 13 to Consolidated Financial Statements), and $520 million to development and exploration. Of the $520 million development budget, we plan to spend $340 million in East Texas and Louisiana, a total of $100 million in the Arkoma, Raton and San Juan Basins, a total of $35 million for development in Alaska, the Permian Basin and Hugoton Royalty Trust properties and $20 million in the Barnett Shale of North Texas. We expect to spend $25 million for exploration.

If acquisitions are available in excess of our $650 million budget, we expect to fund a portion of our 2004 acquisitions with publicly placed equity securities. Strategic property acquisitions during 2004 may alter the amount currently budgeted for development and exploration.

The weak U.S. dollar, raw material shortages and strong demand for steel in China and Europe have tightened worldwide steel supplies, causing prices to rise by more than 50% since November 2003. In response, we have increased our tubular inventory and are currently negotiating contracts with our vendors to support our development program. Should steel prices continue to escalate, our development budget could rise by as much as 10%. While we expect to acquire adequate supplies to complete our development program, a further tightening of steel supplies could restrain the program, limiting our production growth.

We may reevaluate our budget and drilling programs in the event of significant changes in oil and gas prices to focus on opportunities offering the highest rates of return and may increase our budget. Our ability to achieve our production goals will depend on the success of these planned drilling programs or, if property acquisitions are made in place of a portion of the drilling program, the success of those acquisitions.

Acquisitions

In 1999, the Company and Lehman Brothers Holdings, Inc. acquired the common stock of Spring Holding Company, a private oil and gas company, for a combination of cash and XTO Energy's common stock totaling $85 million. The Company and Lehman each owned 50% of a limited liability company that acquired the common stock of Spring. In September 1999, we acquired Lehman's 50% interest in Spring for $44.3 million. This acquisition included oil and gas properties located in the Arkoma Basin of Arkansas and Oklahoma with a purchase price of $235 million. After purchase accounting adjustments and other costs, the cost of the properties was $257 million. We also acquired, with Lehman as 50% owner, Arkoma Basin properties from affiliates of Ocean Energy, Inc. for $231 million. We acquired Lehman's interest in the Ocean Energy Acquisition in March 2000 for $111 million. The 1999 acquisitions, including Lehman's 50% interest in the Spring and Ocean Energy acquisitions, increased reserves by approximately 2.8 million Bbls of oil and 494.7 Bcf of natural gas.

During 2000, we acquired oil- and gas-producing properties for a total cost of $32 million, including $11 million paid to Lehman in March 2000 in excess of our investment in the Ocean Energy Acquisition. There were no individually significant acquisitions in 2000.

During 2001, we acquired predominantly gas-producing properties for a total cost of $242 million. In January 2001, we acquired gas properties in East Texas and Louisiana for $115 million from Herd Producing Company, Inc., and in February 2001, we acquired gas properties in East Texas for $45 million from Miller Energy, Inc. and other owners. In August 2001, we acquired primarily underdeveloped acreage in the Freestone area of East Texas for approximately $22 million. The 2001 acquisitions increased reserves by approximately 248.3 Bcf of natural gas, approximately 50% of which were proved undeveloped.

During 2002, we acquired gas-producing properties for a total cost of $358.1 million. In May 2002, we acquired properties in the Powder River Basin of Wyoming for $101 million. These properties were immediately exchanged with Marathon Oil Company for properties with the same value in East Texas and Louisiana. In July, we purchased gas-producing properties in the San Juan Basin of New Mexico for $43 million and in December 2002, we purchased coal bed methane gas-producing properties located in the San Juan Basin of New Mexico for $153.8 million from J.M. Huber Corporation. The 2002 acquisitions increased reserves by approximately 330.4 Bcf of natural gas, 2.2 million Bbls of natural gas liquids and 449,000 Bbls of oil. Approximately 10% of these reserves were proved undeveloped.

During 2003, we acquired gas-producing properties for a total cost of $629.5 million. In April 2003, we acquired natural gas and coal bed methane producing properties in the Raton Basin of Colorado, the Hugoton Field of southwestern Kansas and the San Juan Basin of New Mexico and Colorado for $381 million from Williams of Tulsa, Oklahoma. In June 2003, we acquired coal bed methane and gas-producing properties in the San Juan Basin of New Mexico and Colorado from Markwest Hydrocarbon, Inc. for $51 million. In October 2003, we announced the completion of property transactions which increased our positions in East Texas, Arkansas and the San Juan Basin of New Mexico for a total cost of $100 million. The 2003 acquisitions increased reserves by approximately 465.7 Bcf of natural gas, 4.5 million Bbls of natural gas liquids and 2.2 million Bbls of oil. Approximately 12% of these reserves were proved undeveloped.

In January 2004, we completed acquisitions with multiple parties for $243 million. The producing properties are located primarily in East Texas and northern Louisiana and will increase our reserves by approximately 182 Bcfe. Our internal engineers estimate that approximately 50% of these reserves are proved developed. In February 2004, we entered definitive agreements with multiple parties for $200 million to acquire producing properties located primarily in the Barnett Shale of North Texas and in the Arkoma Basin. The acquisitions will increase our reserves by approximately 154 Bcfe, of which approximately 52% are proved developed.

Significant Properties

The following table summarizes proved reserves and discounted present value, before income tax, of proved reserves by major operating areas at December 31, 2003:

(in thousands)	Proved Reserves				Discounted Present Value before Income Tax of Proved Reserves	
	Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)	Natural Gas Equivalents (Mcfe)		
Eastern Region	1,887,211	2,738	4,692	1,931,791	$4,261,658	48.3%
San Juan and Raton Basins	798,344	31,940	1,707	1,000,226	1,929,173	21.9%
Arkoma Basin	495,594	-	26	495,750	1,204,674	13.7%
Hugoton Royalty Trust *(a)*	293,171	-	2,390	307,511	623,495	7.1%
Permian Basin	33,133	-	30,508	216,181	392,133	4.4%
Mid-Continent	131,330	-	176	132,386	244,764	2.8%
Alaska Cook Inlet	-	-	15,133	90,798	144,681	1.6%
Other	5,456	-	799	10,250	19,583	0.2%
Total	3,644,239	34,678	55,431	4,184,893	$8,820,161	100%

(a) Includes 200,705,000 Mcf of gas and 1,636,000 Bbls of oil and discounted present value before income tax of $426,845,000 related to our ownership of approximately 54% of Hugoton Royalty Trust units at December 31, 2003. The remainder is our retained interests in the properties underlying the trust's net profits interests.

Eastern Region

We began operations in the East Texas area in 1998 with the purchase of 251 Bcfe of reserves in eight major fields. These properties are located in East Texas and northwestern Louisiana and produce primarily from the Rodessa, Travis Peak, Cotton Valley sandstone, Bossier sandstone and Cotton Valley limestone formations between 7,000 feet and 13,000 feet. Development in the East Texas area has more than doubled reserves since acquisition, and we now have an interest in more than 215,000 gross (171,000 net) acres and a current development inventory of 1,100 to 1,400 wells. We own an interest in 1,422 gross (1,294.4 net) wells that we operate and 192 gross (34.2 net) wells operated by others. Of these wells, 27 gross (25.6 net) operated wells are dual completions. We also own and operate the related gathering facilities.

Freestone Trend

The Freestone Trend area is located in the western shelf of the East Texas Basin in Freestone, Robertson, Limestone and Leon counties. This area includes the Freestone, Bald Prairie, Bear Grass, Oaks, Teague, Farrar, Dew and Luna fields and was our most active gas development area in 2003, where 175 gross (155.8 net) gas wells were drilled and 18 workovers were performed. In 2003, we increased our acreage position to 155,000 gross (121,200 net) acres in this area and have a development inventory of 800 to 1,000 wells. Initial development was concentrated in the Travis Peak formation, but is now focused on multi-pay development of the deeper horizons, including the Cotton Valley and Bossier sandstones and Cotton Valley limestone. A 27-mile pipeline system, completed in January 2002, connects the major fields and allows multiple exit points for marketing. We plan to continue our expansion efforts in this area by drilling approximately 170 wells in 2004. We will also continue to construct and operate infrastructure or contract additional pipeline capacity to support our drilling activity.

Other Eastern Region Fields

Other fields in the Eastern Region include the Opelika, Willow Springs, Whelan, Oak Hill and Carthage fields in the East Texas area and the Middlefork, Oaks/Colquitt, Cotton Valley and Logansport fields in North Louisiana. With our 2003 and January 2004 acquisitions, we increased our position in these areas, which provides opportunities for field extensions and infill drilling. In 2003, we drilled five wells and performed 15 workovers in the other Eastern Region fields. In 2004, we plan to drill 28 wells in the Carthage area and 22 wells in North Louisiana and perform 60 workovers and recompletions. As a part of our 2002 acquisition from Marathon, we acquired an interest in a Cotton Valley gas plant that we now operate. This plant processes approximately 37,000 Mcf of gas per day, and 1,700 Bbls of natural gas liquids per day are extracted, primarily from production in the surrounding operated wells.

San Juan and Raton Basins

The San Juan Basin of northwestern New Mexico and southwestern Colorado contains the largest deposit of natural gas reserves in North America. We acquired a large portion of our interests in the San Juan Basin in December 1997 with the purchase of approximately 290 Bcfe from Amoco Corporation. In 2002, we purchased approximately 212 Bcfe from Marathon Oil Company and J. M. Huber Corporation and extended our coal bed methane operations into Colorado. During 2003, we purchased approximately 311 Bcfe of natural gas and coal bed methane reserves from Williams of Tulsa, Oklahoma. We have now identified 580 to 780 potential drilling locations in the San Juan and Raton Basins. XTO owns an interest in 1,309 gross (1,113.2 net) wells that it operates and 2,204 gross (275.4 net) wells operated by others. Of these wells, 198 gross (169.1 net) operated wells and 134 gross (28.3 net) nonoperated wells are dual completions. In 2003, we participated in the drilling of 94 wells and completed 130 workovers. Drilling focused on the Fruitland Coal formation at shallow intervals of 3,000 feet or less and the Mesaverde and Dakota formations at depths of 3,000 to 7,500 feet. During 2004, we plan to drill 90 to 100 wells and perform 100 to 150 workovers and recompletions, including installation of as many as 60 wellhead compressors and 40 pumping units.

Mesaverde and Dakota Formations

Eighty-acre spacing was approved for the Mesaverde and Dakota formations in January 2002, which now allows wells to be drilled with multiple zone targets. We have identified more than 200 potential well locations that will allow deeper drilling through the Dakota to the Burro Canyon and Morrison sandstones. In 2003, we drilled 22 Dakota and eight Mesaverde wells. Twenty-eight drill wells are planned for 2004.

Fruitland Coal Formation

XTO has centered its Fruitland Coal development efforts on trend extensions. Our coal bed methane play is focused on the northwestern portion of the Basin surrounding the city of Farmington, New Mexico and in the southwestern portion of Colorado. We began drilling Fruitland Coal wells on 160-acre spacing in 2003. We drilled 38 wells in 2003 and plan to drill an additional 25 wells in 2004.

Raton Basin

In 2003, we acquired natural gas and coal bed methane properties in the Raton Basin of Colorado. The Raton Basin is characterized by shallow prolific coal bed methane production, low development cost, available gas market access points and expansive development opportunities. Producing formations include the Raton Coals at depths of 500 to 1,800 feet with coal seams one to twelve feet thick and the Vermejo Coals at depths of 800 to 2,500 feet with coal seams one to twelve feet thick. We drilled 18 wells in this area in 2003 and plan to drill 35 wells in 2004.

Arkoma Basin Area

During 1999, we acquired 480 Bcfe of reserves and a gas gathering system in the Arkoma Basin of Arkansas and Oklahoma. The Arkoma Basin, discovered in the 1920s, extends from central Arkansas into southeastern Oklahoma and is known for shallow production decline rates, multiple formations and complex geology. XTO controls 40% of Arkansas production from the Arkoma Basin and is the largest natural gas producer in Arkansas with over 500,000 gross acres of leasehold. We own an interest in 973 gross (700.7 net) wells which we operate and 716 gross (130.2 net) wells operated by others. Of these wells, 129 gross (91.2 net) operated wells and 83 gross (15.8 net) nonoperated wells are dual completions. Our fault-block analysis technique has identified trapped hydrocarbons in offsetting and new reservoirs across the basin. During 2003, we drilled 79 wells and completed 140 workovers, 55 of which were stimulation/recompletions and 21 of which were wellhead compressor installations. Our properties can be separated into three distinct areas which are the Arkansas Fairway trend, the Arkansas Overthrust trend and the Oklahoma Cromwell/Atoka trend.

Arkansas Fairway Trend

The Arkansas Fairway trend comprises multiple sandstones at depths ranging from 2,500 to 7,500 feet in the Atoka and Morrow intervals. In 2003, the Orr and Hale sandstones were targets for our drilling focused in the Aetna and Cecil fields. Thirty-two wells were drilled and 129 workovers were performed in 2003. In 2004, we plan to drill 30 wells.

Arkansas Overthrust Trend

The Arkansas Overthrust trend area, located south of the Arkansas Fairway trend, typically has multiple thrust faults that created isolated reservoirs. Production is found at varying depths, ranging from 3,500 to 7,500 feet, in the Chismville, Booneville and Gragg fields. This extremely complex geology requires an ongoing process to develop the best exploitation opportunities. The use of electric imaging logs has enhanced the process of identifying new well locations. In 2003, 80-acre well spacing was approved in the Booneville and Chismville fields and 160-acre well spacing was approved in the Gragg Field. This down-spacing added 100 to 150 potential well locations for both operated and non-operated wells. We drilled 29 wells and completed 11 workovers in this area in 2003. We plan to drill 11 wells in 2004.

Oklahoma Cromwell/Atoka Trend

The Oklahoma Cromwell/Atoka trend of southeastern Oklahoma was originally developed in the 1970s targeting the Cromwell sandstones, with the Atoka and Wapanuka limestones as secondary objectives. Development activities were concentrated in the Ashland and South Pine Hollow fields where 18 wells were drilled and four workovers were performed in 2003. In 2004, we plan to drill five wells in this area.

Hugoton Royalty Trust Areas

A substantial portion of properties in the Mid-Continent area, the Hugoton area and the Green River Basin of the Rocky Mountains are subject to an 80% net profits interest conveyed to the Hugoton Royalty Trust as of December 1998. We sold 45.7% of our Hugoton Royalty Trust units in 1999 and 2000.

Mid-Continent Area

XTO is one of the largest producers in the Major and Woodward counties, Oklahoma area of the Anadarko Basin. We operate 576 gross (490.7 net) wells and have an interest in 138 gross (36.8 net) wells operated by others. Oil and gas were first discovered in the Major County area in 1945. The fields in the Major and Woodward counties area are characterized by oil and gas production from a variety of structural and stratigraphic traps. Productive zones range from 6,500 to 9,400 feet and include the Oswego, Red Fork, Inola, Chester, Manning, Mississippian, Hunton and Arbuckle formations.

Development in the Major County area focuses on mechanical improvements, restimulations and recompletions to shallower zones and development drilling. During 2003, we participated in the drilling of four gross (3.2 net) wells in the northwestern portion of the county, targeting the Mississippian formation. We plan to drill seven wells and perform ten workovers in Major County during 2004. We were also very active in Woodward County, Oklahoma, where 12 gross (9.8 net) wells were drilled which targeted the Chester formation. In 2004, we plan to drill up to five wells and to perform as many as five workovers.

We operate a gathering system and pipeline in the Major County area. The gathering system collects gas from over 400 wells through 300 miles of pipeline in the Major County area. The gathering system has current throughput of approximately 16,800 Mcf per day, 70% of which is produced from Company-operated wells. Estimated capacity of the gathering system is 35,000 Mcf per day. Gas is delivered to a processing plant owned and operated by a third party, and then transmitted by an operated residue pipeline to a connection with an interstate pipeline.

Hugoton Area

The Hugoton Field, discovered in 1922, covers parts of Texas, Oklahoma and Kansas and is one of the largest gas fields in North America with an estimated five million productive acres. XTO owns an interest in 372 gross (349.5 net) wells that we operate and 78 gross (18.8 net) wells operated by others. During 2003, we continued our restimulation program in the Chase intervals by completing 37 restimulations. We plan to perform 35 Chase restimulations during 2004.

Approximately 75% of our Hugoton gas production is delivered to the Tyrone Plant, a gas processing plant we operate. During 1998, we completed the acquisition of approximately 70 miles of low pressure gathering lines, increasing production by 3,500 Mcf per day. During 1999 and 2000, we installed additional lateral compressors that lowered the line pressure and increased production in various areas of the Hugoton Field.

Green River Basin

The Green River Basin is located in southwestern Wyoming. We have interests in 188 gross (186.5 net) wells that we operate and 34 gross (4.2 net) wells operated by others in the Fontenelle Field area. Gas production began in the Fontenelle area in the early 1970s and the producing reservoirs are the Cretaceous-aged Frontier, Baxter and Dakota sandstones at depths ranging from 7,500 to 10,000 feet. Development potential for the fields in this area include deepening and opening new producing zones in existing wells, drilling new wells and adding compression to lower line pressures. During 2003, we drilled six gross (6.0 net) wells and performed 11 workovers. During 2004, we plan to perform seven workovers and drill up to seven wells in the Green River Basin.

Permian Basin Area

University Block 9. The University Block 9 Field is located in Andrews County, Texas and was discovered in 1953. We own interests in 82 gross (76.3 net) operated wells. Productive zones are of Wolfcamp, Pennsylvanian and Devonian age and range from 8,400 to 10,000 feet. Development potential includes proper wellbore utilization, recompletions, infill drilling and improvement of waterflood efficiency.

Development in 2003 focused on the Devonian, Grayburg and Wolfcamp formations, where XTO drilled six wells. We also discovered a new shallow Grayburg producing interval. During 2004, we plan to drill up to six wells.

Prentice Field. The Prentice Field is located in Terry and Yoakum counties, Texas. Discovered in 1950, the Prentice Field produces from carbonate reservoirs in the Clear Fork and Glorieta formations at depths ranging from 6,800 to 7,700 feet. The Prentice Field has been separated into several waterflood units for secondary recovery operations. The Prentice Northeast Unit was formed in 1964 with waterflood operations commencing a year later. Development potential exists through infill drilling and improvement of waterflood efficiency.

We operate the Prentice Northeast Unit, where we have a 91.6% working interest in 212 wells. We also own an interest in 71 gross (2.9 net) nonoperated wells. During 2003, we continued our 10-acre development drilling program by drilling 14 gross (12.8 net) vertical wells in the Prentice Field. During 2004, we plan to continue our expansion of the potential infill area by drilling as many as ten wells.

Wasson Field. The Wasson Field, discovered in 1936, is located in Gaines and Yoakum counties, Texas and produces from the San Andres formation at depths ranging from 4,500 to 6,300 feet. The Cornell Unit was formed in 1965 and has development potential that exists through infill drilling and improvement of waterflood efficiency. We have a 68.4% working interest in the unit. In 2003, we drilled four 10-acre infill oil wells and eight gas cap wells, and in 2004 we plan to drill four oil wells and five gas cap wells in this area.

Alaska Cook Inlet Area

In September 1998, we acquired a 100% working interest in two State of Alaska leases and the offshore installations in the Middle Ground Shoal Field of the Cook Inlet. The properties included 27 wells, two operated production platforms set in 70 feet of water about seven miles offshore, and a 50% interest in certain operated production pipelines and onshore processing facilities.

Oil was discovered in the Cook Inlet in 1966 and, to date, more than 130 million Bbls have been produced from the Middle Ground Shoal Field. The field is separated into East and West flanks by a crestal fault. Waterflooding of the East Flank has been successful, but the West Flank has not been fully developed or efficiently waterflooded. Production is primarily from multiple zones within the Miocene-Oligocene-aged Tyonek formation between 7,000 feet and 10,000 feet subsea. We plan to drill up to two East Flank wells in 2004.

Reserves

Definitions of terms used in the following disclosures of oil and natural gas reserves include:

Proved reserves - Estimated quantities of crude oil, natural gas and natural gas liquids which, upon analysis of geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions.

Proved developed reserves - Proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves - Proved reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Estimated future net revenues - Also referred to herein as "estimated future net cash flows." Computational result of applying current prices of oil and gas (with consideration of price changes only to the extent provided by existing contractual arrangements, other than hedge derivatives) to estimated future production from proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves.

Present value of estimated future net cash flows - Also referred to herein as "standardized measure of discounted future net cash flows" or "standardized measure." Computational result of discounting estimated future net revenues at a rate of 10% annually.

The following are estimated quantities of proved reserves and related cash flows as of December 31, 2003, 2002 and 2001:

(in thousands)	December 31 2003	2002	2001
Proved developed:			
Gas (Mcf)	2,651,259	2,042,661	1,452,222
Natural gas liquids (Bbls)	28,187	19,367	14,774
Oil (Bbls)	47,882	47,178	41,231
Mcfe	3,107,673	2,441,931	1,788,252
Proved undeveloped:			
Gas (Mcf)	992,980	838,520	783,256
Natural gas liquids (Bbls)	6,491	6,066	5,525
Oil (Bbls)	7,549	9,171	12,818
Mcfe	1,077,220	929,942	893,314
Total proved:			
Gas (Mcf)	3,644,239	2,881,181	2,235,478
Natural gas liquids (Bbls)	34,678	25,433	20,299
Oil (Bbls)	55,431	56,349	54,049
Mcfe	4,184,893	3,371,873	2,681,566
Estimated future net cash flows:			
Before income tax	$ 17,130,056	$ 10,528,450	$ 3,756,602
After income tax	$ 11,837,447	$ 7,384,215	$ 2,876,728
Present value of estimated future net cash flows, discounted at 10%:			
Before income tax	$ 8,820,161	$ 5,461,298	$ 1,947,441
After income tax	$ 6,128,239	$ 3,873,585	$ 1,522,049

Miller and Lents, Ltd., an independent petroleum engineering firm, prepared the estimates of our proved reserves and the future net cash flows (and related present value) attributable to proved reserves at December 31, 2003, 2002 and 2001. As prescribed by the Securities and Exchange Commission, such proved reserves were estimated using oil and gas prices and production and development costs as of December 31 of each such year, without escalation. Year-end 2003 average realized prices used in the estimation of proved reserves were $5.71 per Mcf for gas, $23.17 per Bbl for natural gas liquids and $30.55 per Bbl for oil. See Note 16 to Consolidated Financial Statements for additional information regarding estimated proved reserves.

Estimated future net cash flows, and the related 10% discounted present value, of year-end 2003 proved reserves are significantly higher than at year-end 2002 because of increased reserves related to acquisitions and development and higher product prices used in the estimation of year-end proved reserves. Year-end 2002 product prices were $4.41 per Mcf for gas, $17.86 per Bbl for natural gas liquids and $29.69 per Bbl for oil.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, 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 change in product prices, may justify revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates.

During 2003, we filed estimates of oil and gas reserves as of December 31, 2002 with the U.S. Department of Energy on Form EIA-23 and Form EIA-28. These estimates are consistent with the reserve data reported for the year ended December 31, 2002 in Note 16 to Consolidated Financial Statements, with the exception that Form EIA-23 includes only reserves from properties that we operate.

Exploration and Production Data

For the following data, "gross" refers to the total wells or acres in which we own a working interest and "net" refers to gross wells or acres multiplied by the percentage working interest owned by us. Although many wells produce both oil and gas, a well is categorized as an oil well or a gas well based upon the ratio of oil to gas production.

Producing Wells

The following table summarizes producing wells as of December 31, 2003, all of which are located in the United States:

	Operated Wells		Nonoperated Wells		Total *(a)*	
	Gross	Net	Gross	Net	Gross	Net
Gas	5,165	4,424.0	3,451	519.4	8,616	4,943.4
Oil	611	538.1	2,137	152.1	2,748	690.2
Total	5,776	4,962.1	5,588	671.5	11,364	5,633.6

(a) 570.0 gross (329.0 net) gas wells and 1.0 gross (1.0 net) oil wells are dual completions.

Drilling Activity

The following table summarizes the number of wells drilled during the years indicated. As of December 31, 2003, we were in the process of drilling 122 gross (61.0 net) wells.

	Year Ended December 31					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Completed as-						
Gas wells	390	289.5	303	227.2	282	200.3
Oil wells	42	30.0	27	15.5	85	33.0
Non-productive	7	3.0	13	5.9	15	5.9
Total	439	322.5	343	248.6	382	239.2
Exploratory wells:						
Completed as-						
Gas wells	12	10.2	-	-	4	2.3
Oil wells	-	-	-	-	1	0.5
Non-productive	-	-	3	1.5	2	1.8
Total	12	10.2	3	1.5	7	4.6
Total *(a)*	451	332.7	346	250.1	389	243.8

(a) Included in totals are 102 gross (17.66 net) wells in 2003, 75 gross (11.2 net) wells in 2002 and 125 gross (16.5 net) wells in 2001 drilled on nonoperated interests.

Acreage

The following table summarizes developed and undeveloped leasehold acreage in which we own a working interest as of December 31, 2003. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed Acres *(a)(b)*		Undeveloped Acres	
	Gross	Net	Gross	Net
Arkansas	525,470	232,290	28,240	20,547
Oklahoma	471,275	329,506	16,766	7,979
Texas	354,901	227,980	69,532	53,071
New Mexico	313,540	194,061	19,715	17,446
Kansas	211,253	167,245	-	-
Colorado	107,900	83,875	-	-
Louisiana	55,733	28,034	-	-
Wyoming	45,007	30,241	572	315
Other	10,038	9,173	-	-
Total	2,095,117	1,302,405	134,825	99,358

(a) Developed acres are acres spaced or assignable to productive wells.

(b) Certain acreage in Oklahoma and Texas is subject to a 75% net profits interest conveyed to the Cross Timbers Royalty Trust, and in Oklahoma, Kansas and Wyoming is subject to an 80% net profits interest conveyed to the Hugoton Royalty Trust.

Oil and Gas Sales Prices and Production Costs

The following table shows the average sales prices per unit of production and the production expense and taxes, transportation and other expense per Mcfe for quantities produced for the indicated period:

	Year Ended December 31		
	2003	2002	2001
Sales prices:			
Gas (per Mcf)	$ 4.07	$ 3.49	$ 4.51
Natural gas liquids (per Bbl)	$ 19.99	$ 14.31	$ 15.41
Oil (per Bbl)	$ 28.59	$ 24.24	$ 23.49
Production expense per Mcfe	$ 0.58	$ 0.57	$ 0.57
Taxes, transportation and other expense per Mcfe	$ 0.37	$ 0.25	$ 0.33

Delivery Commitments

Under a production payment, we have committed to deliver 16 Bcf (13.0 Bcf net to XTO's interest) beginning approximately September 2006. Delivery of the committed volumes is in East Texas. See Note 8 to Consolidated Financial Statements.

The Company's production and reserves are adequate to meet the above delivery commitments.

Competition and Markets

We face competition from other oil and gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases, marketing of oil and gas, and obtaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect XTO's ability to acquire producing properties include available funds, available information about the property and our standards established for minimum projected return on investment. Gathering systems are the only practical method for the intermediate transportation of natural gas. Therefore, competition for natural gas delivery is presented by other pipelines and gathering systems. Competition is also presented by alternative fuel sources, including heating oil, imported liquified natural gas and other fossil fuels. Because of the long-lived, high margin nature of our oil and gas reserves and management's experience and expertise in exploiting these reserves, management believes that it effectively competes in the market.

Our ability to market oil and gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and gas, the proximity of our gas production to pipelines, the available capacity in such pipelines, the demand for oil and gas, and the effects of weather and state and federal regulation. We cannot assure that we will always be able to market all of our production at favorable prices. The Company does not currently believe that the loss of any of our oil or gas purchasers would have a material adverse effect on our operations.

Decreases in oil and gas prices have had and could have in the future an adverse effect on our acquisition and development programs, proved reserves, revenues, profitability, cash flow and dividends. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, "Significant Events, Transactions and Conditions - Product Prices."

Federal and State Regulations

There are numerous federal and state laws and regulations governing the oil and gas industry that are often changed in response to the current political or economic environment. Compliance with this regulatory burden is often difficult and costly and may carry substantial penalties for noncompliance. The following are some specific regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Federal Energy Bill

After failing to pass legislation in 2003, Congress is currently considering a new energy bill. The potential effect of this legislation is unknown, but it is expected to include certain tax incentives for oil and gas producers.

Federal Regulation of Natural Gas

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. Federal wellhead price controls on all domestic gas were terminated on January 1, 1993, and none of our gathering systems are currently subject to FERC regulation. We cannot predict the impact of future government regulation on any natural gas facilities.

Although FERC's regulations should generally facilitate the transportation of gas produced from our properties and the direct access to end-user markets, the future impact of these regulations on marketing XTO's production or on its gas transportation business cannot be predicted. The Company, however, does not believe that it will be affected differently than competing producers and marketers.

Federal Regulation of Oil

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

State Regulation

Oil and gas operations are subject to various types of regulation at the state and local levels. Such regulation includes requirements for drilling permits, the method of developing new fields, the spacing and operations of wells and waste prevention. The production rate may be regulated and the maximum daily production allowable from oil and gas wells may be established on a market demand or conservation basis. These regulations may limit production by well and the number of wells that can be drilled.

We may become a party to agreements relating to the construction or operations of pipeline systems for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the state's administrative authority charged with regulating pipelines. The rates that can be charged for gas, the transportation of gas, and the construction and operation of such pipelines would be subject to the regulations governing such matters. Certain states have recently adopted regulations with respect to gathering systems, and other states are considering similar regulations. New regulations have not had a material effect on the operations of our gathering systems, but XTO cannot predict whether any further rules will be adopted or, if adopted, the effect these rules may have on its gathering systems.

Federal, State or Native American Leases

Our operations on federal, state or Native American oil and gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, Minerals Management Service and other agencies.

Environmental Regulations

Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, and consequently may impact our operations and costs. Management believes that we are in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any material amounts to comply with such regulations, and management does not currently anticipate that future compliance will have a materially adverse effect on the consolidated financial position or results of operations of XTO.

Employees

We had 1,007 employees as of December 31, 2003. None of the employees are represented by a union. We consider our relations with our employees to be good.

Executive Officers of the Company

The executive officers of the Company are elected by and serve until their successors are elected by the Board of Directors.

Bob R. Simpson, 55, was a co-founder of XTO with Mr. Palko and has been Chairman and Chief Executive Officer of the Company since July 1, 1996. Prior thereto, Mr. Simpson served as Vice Chairman and Chief Executive Officer or held similar positions with the Company since 1986. Mr. Simpson was Vice President of Finance and Corporate Development (1979-1986) and Tax Manager (1976-1979) of Southland Royalty Company.

Steffen E. Palko, 53, was a co-founder of XTO with Mr. Simpson and has been Vice Chairman and President or held similar positions with the Company since 1986. Mr. Palko was Vice President - Reservoir Engineering (1984-1986) and Manager of Reservoir Engineering (1982-1984) of Southland Royalty Company.

Louis G. Baldwin, 54, has been Executive Vice President and Chief Financial Officer or held similar positions with the Company since 1986. Mr. Baldwin was Assistant Treasurer (1979-1986) and Financial Analyst (1976-1979) at Southland Royalty Company.

Keith A. Hutton, 45, has been Executive Vice President - Operations or held similar positions with the Company since 1987. From 1982 to 1987, Mr. Hutton was a Reservoir Engineer with Sun Exploration & Production Company.

Vaughn O. Vennerberg II, 49, has been Executive Vice President - Administration or held similar positions with the Company since 1987. Prior to that time, Mr. Vennerberg was employed by Cotton Petroleum Corporation and Texaco Inc. (1979-1986).

Bennie G. Kniffen, 53, has been Senior Vice President and Controller or held similar positions with the Company since 1986. From 1976 to 1986, Mr. Kniffen held the position of Director of Auditing or similar positions with Southland Royalty Company.

Item 3. *LEGAL PROCEEDINGS*

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the U. S. District Court for the Western District of Oklahoma against us and certain of our subsidiaries by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the False Claims Act. The plaintiff alleges that we underpaid royalties on gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% during at least the past 10 years as a result of mismeasuring the volume of gas and incorrectly analyzing its heating content. The plaintiff also alleges that we have failed to pay the fair market value of the carbon dioxide produced. The plaintiff seeks to recover the amount of royalties not paid, together with treble damages, a civil penalty of $5,000 to $10,000 for each violation and attorney fees and expenses. The plaintiff also seeks an order for us to cease the allegedly improper measuring practices. After its review, the Department of Justice decided in April 1999 not to intervene and asked the court to unseal the case. The court unsealed the case in May 1999. A multi-district litigation panel ordered that the lawsuits against us and other companies filed by Grynberg be transferred and consolidated to the federal district court in Wyoming. We believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

In June 2001, we were served with a lawsuit styled *Price, et al. v. Gas Pipelines, et al.* (formerly *Quinque* case). The action was filed in the District Court of Stevens County, Kansas, against us and one of our subsidiaries, along with over 200 natural gas transmission companies, producers, gatherers and processors of natural gas. Plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas working interest owners, overriding royalty owners and royalty owners either from whom the defendants had purchased natural gas or who received economic benefit from the sale of such gas since January 1, 1974. The allegations in the case are similar to those in the *Grynberg* case; however, the *Price* case broadens the claims to cover all oil and gas leases (other than the Federal and Native American leases that are the subject of the *Grynberg* case). The complaint alleges that the defendants have mismeasured both the volume and heating content of natural gas delivered into their pipelines resulting in underpayments to the plaintiffs. Plaintiffs assert a breach of contract claim, negligent or intentional misrepresentation, civil conspiracy, common carrier liability, conversion, violation of a variety of Kansas statutes and other common law causes of action. The amount of damages was not specified in the complaint. In February 2002, we, along with one of our subsidiaries, were dismissed from the suit and another subsidiary of the Company was added. A hearing was held in January 2003, and the court held that a class should not be certified. Plaintiffs' counsel has filed an amended class action petition, which reduces the proposed class to only royalty owners, reduces the claims to mismeasurement of volume only, conspiracy, unjust enrichment and accounting, and only applies as to gas measured in Kansas, Colorado and Wyoming. We believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

On August 5, 2003, the *Price* plaintiffs served one of our subsidiaries with a new original class action petition styled *Price, et al. v. Gas Pipelines, et al.* The action was filed in the District Court of Stevens County, Kansas, against natural gas pipeline owners and operators. Plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The new petition alleges the same improper analysis of gas heating content, which had previously been alleged in the *Price* case discussed above until it was removed from the case by the filing of the amended class action petition. In all other respects, the new petition appears to be identical to the amended class action petition in that it has a proposed class of only royalty owners, alleges conspiracy, unjust enrichment and accounting, and only applies as to gas measured in Kansas, Colorado and Wyoming. The amount of damages was not specified in the complaint. We believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

On April 3, 1998, a class action lawsuit, styled *Booth, et al. v. Cross Timbers Oil Company*, was filed against us in the District Court of Dewey County, Oklahoma. The action was filed on behalf of all persons who, at any time since June 1991, have been paid royalties on gas produced from any gas well within the State of Oklahoma under which we have assumed the obligation to pay royalties. The plaintiffs alleged that we reduced royalty payments by post-production deductions and entered into contracts with subsidiaries that were not arm's-length transactions. The plaintiffs further alleged that these actions reduced the royalties paid to the plaintiffs and those similarly situated, and that such actions were a breach of the leases under which the royalties are paid. In July 2003, we paid $2.5 million to settle the plaintiffs' claims for the period January 1, 1993 through June 30, 2002. Our portion of this liability, net of amounts allocable to Hugoton Royalty Trust units we do not own, was $2.1 million, which had been accrued in our financial statements.

In February 2000, the Department of Interior notified us and several other producers that certain Native American leases located in the San Juan Basin had expired because of the failure of the leases to produce in paying quantities from February through August 1990. The Department of Interior demanded abandonment of the property as well as payment of the gross proceeds from the wells minus royalties paid from the date of the alleged cessation of production to present. In January 2004, the Department of Interior withdrew its claim against us.

We are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management and legal counsel do not believe that the ultimate resolution of these claims, including the lawsuits described above, will have a material effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year.

Item 4. *SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS*

No matters were submitted for a vote of security holders during the fourth quarter of 2003.

PART II

Item 5. *MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS*

Our common stock is listed on the New York Stock Exchange and trades under the symbol "XTO." The following table sets forth quarterly high and low sales prices and cash dividends declared for each quarter of 2003 and 2002 (as adjusted for the five-for-four stock split to be effected on March 17, 2004, and the four-for-three stock split effected on March 18, 2003):

	High	Low	Cash Dividend
2003			
First Quarter	$ 15.888	$ 13.614	$ 0.0080
Second Quarter	17.992	14.560	0.0080
Third Quarter	17.136	14.864	0.0080 *(a)*
Fourth Quarter	23.440	16.744	0.0080
2002			
First Quarter	$ 12.150	$ 8.814	$ 0.0060
Second Quarter	12.930	11.010	0.0060
Third Quarter	12.594	9.210	0.0060
Fourth Quarter	15.834	12.072	0.0060

(a) In September 2003, we distributed as a dividend to our shareholders all of our Cross Timbers Royalty Trust units. This dividend was recorded at a market value of $28.2 million, or approximately $0.12 per common share.

The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Company's Board of Directors and will depend on our financial condition, earnings and funds from operations, the level of our capital expenditures, dividend restrictions in our financing agreements, our future business prospects and other matters as the Board of Directors deems relevant. Although there is a cumulative maximum restriction on distributions to common stockholders under our 7½% senior note and 6¼% senior note covenants, because of retained and projected future earnings, we do not anticipate these restrictions will affect future dividend payments.

On February 17, 2004, the Board of Directors declared a five-for-four stock split to be effected on March 17, 2004, as well as a quarterly dividend of $0.01 per share payable on April 15, 2004 to stockholders of record on March 31, 2004. Because of the five-for-four stock split, this represents a 25% increase in our dividend rate. On March 1, 2004, we had 807 stockholders of record.

Item 6. *SELECTED FINANCIAL DATA*

The following table shows selected financial information for the five years ended December 31, 2003. Significant producing property acquisitions in each of the years presented, other than 2000, affect the comparability of year-to-year financial and operating data. See Items 1 and 2, Business and Properties, "Acquisitions." All weighted average shares and per share data have been adjusted for the five-for-four stock split to be effected on March 17, 2004, the four-for-three stock split effected March 18, 2003 and the three-for-two stock splits effected in September 2000 and June 2001. This information should be read in conjunction with Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements at Item 15(a).

(in thousands except production, per share and per unit data)

	2003	2002	2001	2000	1999
Consolidated Income Statement Data					
Revenues:					
Gas and natural gas liquids	$ 1,040,370	$ 681,147	$ 710,348	$ 456,814	$ 239,056
Oil and condensate	135,058	115,324	116,939	128,194	86,604
Gas gathering, processing and marketing	12,982	11,622	12,832	16,123	10,644
Other	1,145	2,070	(1,371)	(280)	4,991
Total Revenues	$ 1,189,555	$ 810,163	$ 838,748	$ 600,851	$ 341,295
Earnings available to common stock	$ 288,279 *(a)*	$ 186,059 *(b)*	$ 248,816 *(c)*	$ 115,235 *(d)*	$ 44,964 *(e)*
Per common share					
Basic	$ 1.28 *(f)*	$ 0.89	$ 1.22 *(g)*	$ 0.65	$ 0.26
Diluted	$ 1.27 *(f)*	$ 0.88	$ 1.20 *(g)*	$ 0.61	$ 0.24
Weighted average common shares outstanding	224,749	208,375	204,176	177,884	175,569
Cash dividends declared per common share	$ 0.0320 *(h)*	$ 0.0240	$ 0.0220	$ 0.0134	$ 0.0110
Consolidated Statement of Cash Flows Data					
Cash provided (used) by:					
Operating activities	$ 794,181	$ 490,842	$ 542,615	$ 377,421	$ 133,301
Investing activities	$ (1,135,234)	$ (736,817)	$ (610,923)	$ (133,884)	$ (156,370)
Financing activities	$ 333,094	$ 254,119	$ 67,680	$ (241,833)	$ 16,470
Consolidated Balance Sheet Data					
Property and equipment, net	$ 3,312,067	$ 2,370,965	$ 1,841,387	$ 1,357,374	$ 1,339,080
Total assets	$ 3,611,134	$ 2,648,193	$ 2,132,327	$ 1,591,904	$ 1,477,081
Long-term debt	$ 1,252,000	$ 1,118,170	$ 856,000	$ 769,000	$ 991,100
Stockholders' equity	$ 1,465,642	$ 907,786	$ 821,050	$ 497,367	$ 277,817
Operating Data					
Average daily production:					
Gas (Mcf)	668,436	513,925	416,927	343,871	288,000
Natural gas liquids (Bbls)	6,463	5,068	4,385	4,430	3,631
Oil (Bbls)	12,943	13,033	13,637	12,941	14,006
Mcfe	784,877	622,532	525,062	448,098	393,826
Average sales price:					
Gas (per Mcf)	$ 4.07	$ 3.49	$ 4.51	$ 3.38	$ 2.13
Natural gas liquids (per Bbl)	$ 19.99	$ 14.31	$ 15.41	$ 19.61	$ 11.80
Oil (per Bbl)	$ 28.59	$ 24.24	$ 23.49	$ 27.07	$ 16.94
Production expense (per Mcfe)	$ 0.58	$ 0.57	$ 0.57	$ 0.53	$ 0.53
Taxes, transportation and other expense (per Mcfe)	$ 0.37	$ 0.25	$ 0.33	$ 0.35	$ 0.23
Proved reserves:					
Gas (Mcf)	3,644,239	2,881,181	2,235,478	1,769,683	1,545,623
Natural gas liquids (Bbls)	34,678	25,433	20,299	22,012	17,902
Oil (Bbls)	55,431	56,349	54,049	58,445	61,603
Mcfe	4,184,893	3,371,873	2,681,566	2,252,425	2,022,653
Other Data					
Ratio of earnings to fixed charges *(i)*	6.9	5.6	7.7	2.8	1.9

(a) Includes pre-tax effects of a derivative fair value loss of $10.2 million, non-cash contingency gain of $1.7 million, non-cash incentive compensation of $53.1 million, a $9.6 million loss on extinguishment of debt and a $16.2 million non-cash gain on the distribution of Cross Timbers Royalty Trust units, and a $1.8 million after-tax gain on adoption of the new accounting standard for asset retirement obligation.

(b) Includes pre-tax effects of a derivative fair value gain of $2.6 million, gain on settlement with Enron Corporation of $2.1 million, non-cash incentive compensation of $27 million and an $8.5 million loss on extinguishment of debt.

(c) Includes pre-tax effects of a derivative fair value gain of $54.4 million and non-cash incentive compensation of $9.6 million, and an after-tax charge of $44.6 million for the cumulative effect of accounting change.

(d) Includes pre-tax effects of a gain of $43.2 million on significant asset sales, derivative fair value loss of $55.8 million and non-cash incentive compensation expense of $26.1 million.

(e) Includes pre-tax effect of a $40.6 million gain on sale of Hugoton Royalty Trust units.

(f) Before cumulative effect of accounting change, earnings per share were $1.27 basic and $1.26 diluted.

(g) Before cumulative effect of accounting change, earnings per share were $1.44 basic and $1.41 diluted.

(h) Excludes the September 2003 distribution of all of the Cross Timbers Royalty Trust units owned by the Company to its stockholders as a dividend with a market value of approximately $0.12 per common share.

(i) For purposes of calculating this ratio, earnings are before income tax and fixed charges. Fixed charges include interest costs and the portion of rentals considered to be representative of the interest factor.

Item 7. ***MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

The following discussion and analysis should be read in conjunction with Item 6, "Selected Financial Data" and our Consolidated Financial Statements at Item 15(a). Unless otherwise indicated, throughout this discussion the term "Mcfe" refers to thousands of cubic feet of gas equivalent quantities produced for the indicated period, with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf. All shares and per share data have been adjusted for the five-for-four stock split to be effected on March 17, 2004.

Overview

Our business is to produce and sell natural gas, natural gas liquids and crude oil from our predominantly southwestern and central U.S. properties, most of which we operate. Because we consider our gathering, processing and marketing as ancillary functions to our production of natural gas, natural gas liquids and crude oil, we have determined that our business comprises only one industry segment.

In 2003, XTO Energy achieved the following record financial and operating results:

– Average daily gas production was 668 million cubic feet, a 30% increase from 2002, and average daily natural gas liquid production was 6,463 barrels, a 28% increase from 2002.

– Year-end proved reserves were 4.185 trillion cubic feet of gas equivalent, a 24% increase from year-end 2002.

– Net income was $288.3 million, a 55% increase from 2002, and earnings per basic common share was $1.28, a 44% increase from 2002.

– Cash flow from operating activities was $794.2 million, a 62% increase from 2002.

– Stockholders' equity was $1.47 billion, a 61% increase from year-end 2002.

– The debt-to-capitalization ratio was 46% at year-end 2003, down from 55% at year-end 2002.

We achieve production and proved reserve growth generally through producing property acquisitions, followed by development. Development activities are generally funded by cash flow from operating activities. Funding sources for our acquisitions include proceeds from sales of public equity and debt, bank borrowings, cash flow from operating activities, or a combination of these sources. Maintaining or improving our debt-to-capitalization ratio is a primary consideration in selecting our method of acquisition financing.

After considering acquisitions announced through February 2004, our goal for 2004 is to increase natural gas production by 18% to 20%. To achieve future production and reserve growth, we will continue to pursue acquisitions that meet our criteria, and to complete development projects included in our inventory of approximately 2,700 potential development drilling locations. Our 2004 acquisition budget is $650 million, of which $243 million was spent on acquisitions in January 2004. We also entered agreements in February 2004 to acquire properties in April 2004 for $200 million. After considering these acquisitions, our 2004 development budget is $520 million. We cannot ensure that we will be able to find properties that meet our acquisition criteria and that we can purchase on acceptable terms.

The weak U.S. dollar, raw material shortages and strong demand for steel in China and Europe have tightened worldwide steel supplies, causing prices to rise by more than 50% since November 2003. In response, we have increased our tubular inventory and are currently negotiating contracts with our vendors to support our development program. Should steel prices continue to escalate, our development budget could rise by as much as 10%. While we expect to acquire adequate supplies to complete our development program, a further tightening of steel supplies could restrain the program, limiting our production growth.

Sales prices for our natural gas and oil production are influenced by supply and demand conditions over which we have little or no control, including weather and regional and global economic conditions. To provide predictable production growth, we hedge a portion of our production at prices that ensure stable cash flow margins to fund our operating commitments and development program. As of March 5, 2004, we have hedged approximately half of our 2004 projected gas production at an average NYMEX price of $4.77 per Mcf. Our average realized price on hedged production will be lower than this average NYMEX price because of location, quality and other adjustments.

The combined effect of higher product prices and a 30% increase in gas production resulted in a 47% increase in total revenues to $1.19 billion in 2003 from $810.2 million in 2002. On an Mcfe produced basis, total revenues were $4.15 in 2003, a 16% increase from $3.57 in 2002.

We analyze, on an Mcfe produced basis, expenses that generally trend changes in production:

	2003	2002	% Increase (Decrease)
Production	$ 0.58	$ 0.57	2%
Taxes, transportation and other	0.37	0.25	48%
Depreciation, depletion and amortization	0.99	0.90	10%
General and administrative, excluding non-cash incentive compensation	0.19	0.15	27%
Interest	0.22	0.24	(8%)
	$2.35	$ 2.11	

The 48% increase in taxes, transportation and other expense is primarily because of increased product prices. Depreciation, depletion and amortization increased 10% because of higher acquisition and development costs. The 27% increase in general and administrative expense is because of increased personnel and other costs related to Company growth.

Significant expenses that generally do not trend with production include:

Non-cash incentive compensation. This is a component of general and administrative expense and primarily relates to the vesting of performance shares when the common stock price reaches specified target levels. Non-cash incentive compensation was $53.1 million in 2003, a 97% increase from the comparable 2002 expense of $27 million. Increased incentive compensation is because of the 53% increase in the common stock price during 2003 and the resulting increased value of vested awards. After adjusting for the effect of the April 2003 common stock offering, non-cash incentive compensation was approximately 2.8% of the increase in market capitalization of outstanding common shares during each of 2003 and 2002. Including non-cash incentive compensation, general and administrative expense increased $45.6 million, or 73%.

Derivative fair value (gain) loss. This is the net realized and unrealized gain or loss on derivative financial instruments that do not qualify for hedge accounting treatment, and fluctuates based on changes in the fair value of underlying commodities. The derivative fair value loss was $10.2 million in 2003 as compared with a gain of $2.6 million in 2002. The loss in 2003 is generally related to higher natural gas prices during the year.

Accretion of discount in asset retirement obligation. This expense recognizes the increase, related to the passage of time, in the estimated costs to abandon and remediate our producing properties at the end of their productive lives. The accretion of discount expense was $5.3 million in 2003, the first year of its recognition since the related accounting pronouncement was adopted January 1, 2003.

Our primary sources of liquidity are cash flow from operating activities, borrowings under our revolving credit facility with commercial banks and public offerings of equity and debt. In September 2003, Moody’s assigned to the Company an SGL-1 liquidity rating, its highest rating. In January 2004, Standard & Poors upgraded our corporate credit rating to investment grade and all liens on producing properties and other collateral were irrevocably released as security for our revolving credit facility. As a result, Moody's upgraded our existing senior notes to Ba1 from Ba2 and confirmed our Ba1 senior implied rating.

In February 2004, we entered a new revolving credit facility with an interest rate based on the London Interbank Offered Rate plus 1% and an initial commitment amount of $800 million which may be increased to $1 billion. As of February 27, 2004, our borrowings under this facility were $169 million. Under the terms of the agreement, we must maintain a debt-to-capitalization ratio, as adjusted for certain accounting items, of no more than 60%.

Our consolidated financial position and results of operations are significantly affected by our critical accounting policies. We utilize the successful efforts method of oil and gas accounting, under which we expense the costs of unsuccessful exploratory well costs, as well as exploratory geological and geophysical costs. All acquisition and development costs are generally capitalized and expensed through depreciation, depletion and amortization, which is computed on the unit-of-production method. If conditions indicate our properties may be impaired, we estimate future net cash flows from the applicable properties and compare this estimate to our total net cost of the properties. If the property cost cannot be recovered from the estimated future cash flows, we must write down the property cost to the discounted present value of such future net cash flows. To date, our impairment of producing properties has been limited to a $2 million provision recorded in 1998. While we do not expect significant impairment provisions in the near future, any prolonged significant decline in commodity prices could require an impairment adjustment to our property cost.

Significant Events, Transactions and Conditions

The following events, transactions and conditions affect the comparability of results of operations and financial condition for the years ended December 31, 2003, 2002 and 2001 and may impact future operations and financial condition.

Acquisitions. We acquired primarily gas-producing properties at a total cost of $629.5 million in 2003, $358.1 million in 2002 and $242 million in 2001, which have been funded by a combination of proceeds from sales of common stock and senior notes, bank borrowings and cash flow from operating activities. The following are the more significant acquisitions:

Closing Date		Seller	Amount (in millions)	Acquisition Area
2003	May	Williams of Tulsa, Oklahoma	$ 381	Raton Basin of Colorado, Hugoton field of southwestern Kansas and San Juan Basin of New Mexico
	June	Markwest Hydrocarbon, Inc.	51	San Juan Basin of New Mexico and Colorado
	October	Multiple parties	100	East Texas, Arkansas and San Juan Basin of New Mexico
2002	May	Marathon Oil Company	101	East Texas and Louisiana
	July	Marathon Oil Company	43	San Juan Basin of New Mexico
	December	J.M. Huber Corporation	154	San Juan Basin of Colorado
2001	January	Herd Producing Company, Inc.	115	East Texas and Louisiana
	February	Miller Energy, Inc.	45	East Texas

In January 2004, we acquired from multiple parties producing properties located primarily in East Texas and northern Louisiana for $243 million. In February 2004, we entered definitive agreements with multiple parties to acquire producing properties located primarily in the Barnett Shale of North Texas and in the Arkoma Basin for $200 million, with an expected closing date of April 2004. See Note 13 to Consolidated Financial Statements.

2003, 2002 and 2001 Development and Exploration Programs. Gas development focused on the East Texas area and the Arkoma and San Juan basins during 2003, 2002 and 2001. Oil development was concentrated in Alaska and in the University Block 9 Field during all three years. Development costs totaled $460.2 million in 2003, $354.1 million in 2002 and $385.5 million in 2001. Exploration activity has been primarily geological and geophysical analysis, including seismic studies, of undeveloped properties. Exploratory expenditures were $1.8 million is 2003, $2.2 million in 2002 and $5.4 million in 2001. Exploration expense for 2001 includes dry hole expense of $2.2 million. Our development and exploration activities are generally funded by cash flow from operating activities.

2004 Acquisition, Development and Exploration Program. We have budgeted $1.17 billion for our 2004 development and acquisition programs, which is expected to be substantially funded by cash flow from operations. We plan to allocate $650 million of the 2004 capital budget to acquisitions, including $243 million of acquisitions in January 2004 and $200 million expected to close in April 2004. The remaining $520 million is to fund development and exploration projects, approximately 5% of which will be used for exploration. The cost of 2004 property acquisitions may alter the amount currently budgeted for development and exploration. Also, because of recent worldwide steel shortages, our development budget may be increased by as much as 10%. The total capital budget, including acquisitions, will be adjusted throughout 2004 to focus on opportunities offering the highest rates of return.

As of December 31, 2003, we have an inventory of approximately 2,700 potential drilling locations. We plan to drill about 420 (336 net) development wells and perform approximately 350 (251 net) workovers and recompletions in 2004. Drilling plans are dependent upon product prices and the availability of drilling equipment.

Product Prices. In addition to supply and demand, oil and gas prices are affected by seasonal, political and other conditions we generally cannot control or predict.

Gas. Natural gas prices are dependent upon North American supply and demand, which is affected by weather and economic conditions. Natural gas competes with alternative energy sources as a fuel for heating and the generation of electricity. Gas prices were at record highs at the beginning of 2001 because of gas supplies strained by winter weather. Throughout the remainder of 2001, prices declined because of fuel switching related to higher prices, milder weather and reduced demand from a weaker economy. The winter of 2001-2002 was one of the warmest on record, resulting in higher than average gas storage levels and lower gas prices in 2002. Prices climbed in fourth quarter 2002 as a result of low levels of drilling activity, increased industrial demand, colder weather and international instability. With colder than normal weather, record low gas storage levels and continued increasing demand, gas prices remained relatively high during the first five months of 2003. With diminished demand related to higher prices, natural gas prices were lower during the summer months, then rose with cooler weather in the fall and early winter. Prices in 2004 will continue to be affected by weather, the recovery of the domestic economy, increases in the level of North American production and import levels of liquified natural gas. In any case, management expects natural gas prices to remain volatile. As described under "Hedging Activities" below, we use commodity price hedging instruments to reduce our exposure to gas price fluctuations. The following are comparative average gas prices for the last three years:

	Year Ended December 31		
(per Mcf)	2003	2002	2001
Average NYMEX price	$ 5.39	$ 3.22	$ 4.27
Average realized sales price	$ 4.07	$ 3.49	$ 4.51
Average realized sales price excluding hedging	$ 4.86	$ 2.98	$ 3.87

At March 5, 2004, the average NYMEX gas price for the following 12 months was $5.71 per MMBtu. As computed on an energy equivalent basis, our proved reserves were 87% natural gas at December 31, 2003. After considering hedges in place as of March 5, 2004, we estimate that a $0.10 per Mcf increase or decrease in the average gas sales price would result in a $12.2 million change in 2004 annual operating cash flow.

Oil. Crude oil prices are generally determined by global supply and demand. After beginning 2001 relatively strong, oil prices declined through the remainder of the year and in 2002 because of lagging demand caused by a global recession. Rising uncertainties in the Middle East and OPEC production discipline led to higher prices late in 2002. OPEC members agreed to increase daily oil production 1.5 million barrels beginning February 2003, to help stabilize a volatile world market. Oil prices remained relatively high in 2003, however, because of the war in Iraq, slower than anticipated resumption of Iraqi oil exports and unusually low storage levels. OPEC reiterated its intent to maintain oil prices by reducing daily oil production by 2 million barrels beginning June 2003 and by an additional 900,000 barrels beginning November 2003. In January 2004, a combination of below normal temperatures and low U.S. oil supplies led oil prices to ten-month highs, reaching $36 per Bbl. Despite increasing demand, OPEC members agreed to reduce daily oil production by one million barrels beginning April 2004 to maintain market balance in the seasonally low demand second quarter. As described under "Hedging Activities" below, we use commodity price hedging instruments to reduce our exposure to oil price fluctuations. The following are comparative average oil prices for the last three years:

	Year Ended December 31		
(per Bbl)	2003	2002	2001
Average NYMEX price	$31.08	$26.10	$26.00
Average realized sales price	$28.59	$24.24	$23.49
Average realized sales price excluding hedging	$29.40	$24.52	$23.49

At March 5, 2004, the average NYMEX oil price for the following 12 months was $33.90 per Bbl. We estimate that a $1.00 per barrel increase or decrease in the average oil sales price would result in approximately a $4.4 million change in 2004 annual operating cash flow.

Hedging Activities. We enter futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts, to hedge our exposure to product price volatility. Our policy is to routinely hedge a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the benefit of rising prices, management plans to continue its hedging strategy because of the benefits of more predictable production growth and cash flows.

In 2003, all hedging activities decreased gas revenue by $193 million and decreased oil revenue by $3.9 million, while in 2002, hedging activities increased gas revenue by $95.4 million and decreased oil revenue by $1.3 million. All hedging activities increased gas revenue by $97 million in 2001.

The following summarizes our January 2004 through December 2005 natural gas NYMEX hedging positions at March 5, 2004, excluding basis adjustments which have been separately hedged. As of February 2004, our daily gas production was approximately 774,000 Mcf. Prices to be realized for hedged production will be less than these NYMEX prices because of location, quality and other adjustments. See Note 8 to the Consolidated Financial Statements.

		Futures Contracts and Swap Agreements	
Production Period		Mcf per Day	Average NYMEX Price per Mcf
2004	January to June	380,000	$ 4.77
	July to December	400,000	$ 4.77
2005	January to December	100,000	$ 5.21

Cumulative Effect of Accounting Change for Derivatives. On January 1, 2001, we adopted Statement of Financial Accounting Standards (SFAS) No. 133 by recording a one-time after-tax charge of $44.6 million in the income statement for the cumulative effect of a change in accounting principle and an unrealized loss of $67.3 million in accumulated other comprehensive income, which is an element of stockholders' equity. The unrealized loss was related to the derivative fair value of cash flow hedges. The charge to the income statement was primarily related to our gas physical delivery contract with crude oil-based pricing.

Derivative Fair Value Gain/Loss. We record in our income statements realized and unrealized derivative fair value gains and losses related to derivatives that do not qualify for hedge accounting, as well as the ineffective portion of hedge derivatives. We recorded a $10.2 million loss in 2003, a $2.6 million gain in 2002 and a $54.4 million gain in 2001 related to changes in fair value of these non-hedge derivatives. The 2001 gain includes $29.5 million related to the change in fair value of call options that we sold in 1999 as part of our hedging activities. Because written call options do not provide protection against declining prices, they do not qualify for hedge or loss deferral accounting. Most of the remaining gain in 2001 is related to the change in fair value of a gas physical delivery contract with crude oil-based pricing, the loss on which was initially recorded in the cumulative effect of accounting change for derivatives.

Unrealized derivative gains and losses associated with effective cash flow hedges are recorded in accumulated other comprehensive income. At December 31, 2003, we have an unrealized pre-tax loss of $81.9 million in accumulated other comprehensive income related to the fair value of derivatives designated as cash flow hedges of gas price risk. Based on December 31 mark-to-market prices, $81.4 million of this fair value loss is expected to be reclassified into earnings through December 2004. The actual reclassification to earnings will be based on mark-to-market prices at contract settlement date.

Non-Cash Incentive Compensation. Incentive compensation generally results from vesting of performance share awards as our common stock price increases. Non-cash incentive compensation totaled $53.1 million in 2003, $27 million in 2002 and $9.6 million in 2001, which relates to increases in our stock price of 53% in 2003 and 41% in 2002. After adjusting for the effects of the April 2003 common stock offering, non-cash incentive compensation was approximately 2.8% of the increase in market capitalization of outstanding common shares during each of 2003 and 2002. As of December 31, 2003, outstanding performance shares comprise 250,000 shares that vest when the common stock price reaches $23.86, 296,000 shares that vest when the common stock prices reaches $24.00, 275,000 shares that vest when the common stock price reaches $26.00 and 275,000 shares that vest when the common stock price reaches $28.00. As of March 2, 2004, the common stock price reached a high of $26.00, resulting in vesting of 821,000 performance shares outstanding at year end 2003, as well as 500,000 additional shares that were granted in February and March 2004 with vesting at $24.86 and $25.86. Total non-cash incentive compensation related to 2004 vesting of performance shares through March 2 was $32.9 million. In March 2004, an additional 250,000 shares were granted that vest when the common stock price reaches $26.86.

Cross Timbers Royalty Trust Distribution. In August 2003, our Board of Directors declared a dividend of 0.0059 units of Cross Timbers Royalty Trust for each share of our common stock outstanding on September 2, 2003. This dividend, totaling 1,360,000 units, was distributed on September 18, 2003, after which we no longer own any Cross Timbers Royalty Trust units. We recorded this dividend at $28.2 million, or approximately $0.12 per common share, based on the fair market value of the units on the distribution date. After considering the cost of the units, we recorded a gain on distribution of $16.2 million.

Extinguishment of Debt. We purchased and canceled $9.7 million of our 9¼% senior subordinated notes in April 2002, and redeemed the remaining $115.3 million of the 9¼% notes in June 2002. In November 2002, we purchased and canceled $11.8 million of our 8¾% senior subordinated notes and redeemed the remaining $163.2 million of the 8¾% notes in May 2003. As a result of these transactions, we recorded a total pre-tax loss on extinguishment of debt of $9.6 million in 2003 and $8.5 million in 2002, which includes the effects of redemption premium paid and expensing related deferred debt costs.

Enron Corporation Bankruptcy and Settlement. In December 2001, after Enron Corporation filed for bankruptcy, we had recorded a $21.4 million receivable from Enron and a $43.3 million Btu swap contract payable to Enron. In December 2002, we paid Enron Corporation $6 million in settlement of all claims, resulting in recognition of $14.1 million in gas revenue and a $2.1 million gain.

Cumulative Effect of Accounting Change for Asset Retirement Obligation. On January 1, 2003, we adopted SFAS No. 143 by recording a long-term liability for asset retirement obligation of $75.3 million, an increase in property cost of $60.7 million, a reduction of accumulated depreciation, depletion and amortization of $17.3 million and a cumulative effect of accounting change gain, net of tax, of $1.8 million. As of December 31, 2003, our recorded asset retirement obligation was $93.4 million, after considering the liability incurred for wells drilled and acquired and discount accretion during 2003.

Impairment Provision. We evaluate possible impairment of producing properties when conditions warrant. This evaluation is based on an assessment of recoverability of net property costs from estimated future net cash flows from those properties. Estimated future net cash flows are based on management's best estimate of projected oil and gas reserves and prices. We have not recorded impairment of producing properties since a $2 million provision was recorded in 1998. If oil and gas prices significantly decline, we may be required to record impairment provisions for producing properties in the future, which could be material.

Liquidity and Investment Grade Ratings. In September 2003, Moody's assigned the Company an SGL-1 liquidity rating, its highest rating. In January 2004, Standard & Poors upgraded our corporate credit rating to investment grade. At that time, all liens on producing properties and other collateral were irrevocably released as security for our revolving credit agreement with commercial banks. Also in January 2004, Moody's upgraded our existing senior notes to Ba1 from Ba2 and confirmed our Ba1 senior implied rating.

Senior Note Offering. In April 2002, we sold $350 million of 7½% senior notes due April 2012, and in April 2003, we sold $400 million of 6¼% senior notes due April 2013. In January 2004, we sold $500 million of 4.9% senior notes due February 2014. Proceeds from the senior notes were used to fund property acquisitions, redeem senior subordinated notes and reduce bank debt.

Common Stock Transactions. In April 2003, we sold 17.3 million shares of common stock with net proceeds of approximately $248 million. The proceeds and net proceeds from the concurrent sale of senior notes were used to fund our producing property acquisition from Williams, to redeem our 8¾% senior subordinated notes and to reduce bank debt.

Results of Operations

2003 Compared to 2002

For the year 2003, net income was $288.3 million compared with net income of $186.1 million for 2002. Earnings for 2003 include the net after-tax effects of non-cash incentive compensation of $34.5 million, loss on extinguishment of debt of $6.2 million, a $6.6 million fair value loss on certain derivatives that do not qualify for hedge accounting, a non-cash contingency gain of $1.1 million, a non-cash gain of $10.5 million resulting from the distribution of Cross Timbers Royalty Trust units as a dividend to common stockholders and a $1.8 million gain on the cumulative effect of the accounting change for adoption of SFAS No. 143 for asset retirement obligation. Earnings for 2002 include a $17.5 million after-tax charge for non-cash incentive compensation, a $5.5 million after-tax charge for extinguishment of debt, a $1.3 million after-tax gain on a settlement with Enron Corporation and a $1.7 million after-tax derivative fair value gain on certain derivatives that do not qualify for hedge accounting.

Revenues for 2003 were $1.19 billion, or 47% higher than 2002 revenues of $810.2 million. Gas and natural gas liquids revenue increased $359.2 million, or 53%, because of a 30% increase in gas production and a 17% increase in gas prices from an average of $3.49 per Mcf in 2002 to $4.07 in 2003, as well as a 40% increase in natural gas liquids prices from an average price of $14.31 per Bbl in 2002 to $19.99 in 2003 and a 28% increase in natural gas liquids production (see "Significant Events, Transactions and Conditions – Product Prices – Gas" above). Increased production was attributable to the 2003 acquisition and development program.

Oil revenue increased $19.7 million, or 17%, primarily because of an 18% increase in oil prices from an average of $24.24 per Bbl in 2002 to $28.59 in 2003 (see "Significant Events, Transactions and Conditions – Product Prices – Oil" above). A 1% decrease in production is the result of natural decline, partially offset by development.

Gas gathering, processing and marketing revenues increased $1.4 million primarily because of higher natural gas liquids prices and margins. Other revenues of $2.1 million in 2002 represent the gain on a settlement with Enron Corporation.

Expenses for 2003 totaled $687.9 million as compared with total 2002 expenses of $461.3 million. Excluding derivative fair value (gain) loss, expenses for 2003 totaled $677.7 million, or 46% above total expenses of $463.9 million for 2002. Most expenses increased in 2003 because of increased production from acquisitions and development and related Company growth.

Production expense increased $35.7 million, or 28%, because of higher production related to acquisitions and development. Production expense per Mcfe increased slightly from $0.57 to $0.58 because of increased fuel costs. Taxes, transportation and other increased 83%, or $47.4 million, primarily because of significantly higher oil and gas prices, increased production, higher transportation fuel prices and higher property taxes related to drilling and acquisitions. Taxes, transportation and other per Mcfe increased 48% from $0.25 to $0.37 primarily due to higher product prices.

Depreciation, depletion and amortization (DD&A) increased $79.9 million, or 39%, primarily because of increased production and higher acquisition costs. On an Mcfe basis, DD&A increased from $0.90 in 2002 to $0.99 in 2003 because of higher acquisition and development costs.

General and administrative expense increased $45.6 million, or 73%, because of an increase of $26.1 million in non-cash incentive compensation and increased expenses from Company growth. Excluding non-cash incentive compensation, general and administrative expense per Mcfe increased 27% from $0.15 in 2002 to $0.19 in 2003.

The derivative fair value loss for 2003 was $10.2 million compared to 2002 derivative fair value gain of $2.6 million. The 2003 loss is primarily related to the effect of higher gas prices on the fair value of Btu swap contracts and the ineffective portion of hedge derivatives. The 2002 gain is primarily the result of declining gas prices on derivatives that do not qualify for hedge accounting. See Note 7 to Consolidated Financial Statements.

Interest expense increased $10.2 million, or 19%, primarily because of a 24% increase in the weighted average borrowings to partially fund property acquisitions, offset by a 6% decrease in the weighted average interest rate. Interest expense per Mcfe decreased 8% from $0.24 in 2002 to $0.22 in 2003 because higher production offset increased borrowings.

During 2003, we recognized a $9.6 million loss on extinguishment of debt related to the redemption of our 8¾% senior subordinated notes, compared with the recognition in 2002 of an $8.5 million loss on extinguishment of debt primarily related to the redemption of our 9¼% senior subordinated notes. During 2003, we also recognized a $16.2 million gain on the distribution of Cross Timbers Royalty Trust units as a dividend to common stockholders. See Notes 3 and 14 to Consolidated Financial Statements.

2002 Compared to 2001

For the year 2002, net income was $186.1 million compared with net income of $248.8 million for 2001. Earnings for 2002 include the net after-tax effects of non-cash incentive compensation of $17.5 million, loss on extinguishment of debt of $5.5 million, gain on settlement with Enron of $1.3 million and a $1.7 million fair value gain on derivatives that do not qualify for hedge accounting. The 2001 earnings include a $44.6 million after-tax charge for adoption of the derivative accounting principle, SFAS No. 133, an after-tax derivative fair value gain of $35.3 million and a $6.4 million after-tax charge for incentive compensation and loss on sale of properties.

Revenues for 2002 were $810.2 million, or 3% lower than 2001 revenues of $838.7 million. Gas and natural gas liquids revenue decreased $29.2 million, or 4%, because of a 23% decrease in gas prices from an average of $4.51 per Mcf in 2001 to $3.49 in 2002 and a 7% decrease in natural gas liquids prices from an average price of $15.41 per Bbl in 2001 to $14.31 in 2002 (see "Significant Events, Transactions and Conditions – Product Prices – Gas" above). These decreases were largely offset by a 23% increase in gas production and a 16% increase in natural gas liquids production. Increased production was attributable to the 2002 development program.

Oil revenue decreased $1.6 million, or 1%, because of a 4% decrease in oil production, partially offset by a 3% increase in oil prices from an average of $23.49 per Bbl in 2001 to $24.24 in 2002 (see "Significant Events, Transactions and Conditions – Product Prices – Oil" above). Decreased production is the result of natural decline, partially offset by development.

Gas gathering, processing and marketing revenues decreased $1.2 million primarily because of lower natural gas liquids prices and lower margins. Other revenues of $2.1 million in 2002 represent the gain on the Enron settlement.

Expenses for 2002 totaled $461.3 million as compared with total 2001 expenses of $327.8 million. Excluding derivative fair value (gain) loss, expenses for 2002 totaled $463.9 million, or 21% above total expenses of $382.2 million for 2001. Most expenses increased in 2002 because of increased production from acquisitions and development.

Production expense increased $19.2 million, or 17%, because of higher production related to acquisitions and development. Production expense per Mcfe remained unchanged at $0.57. Our 2002 exploration expense was $2.2 million compared with the 2001 expense of $5.4 million, which included dry hole costs of $2.2 million.

Taxes, transportation and other decreased 10%, or $6.4 million, primarily because of lower product prices, lower severance tax rates on new wells in East Texas and lower transportation fuel prices, partially offset by increased property taxes on certain new East Texas wells. With the combined effect of increased production, per Mcfe taxes, transportation and other decreased 24% from $0.33 to $0.25.

DD&A increased $49.8 million, or 32%, primarily because of increased production and higher drilling costs. On an Mcfe basis, DD&A increased from $0.81 in 2001 to $0.90 in 2002.

General and administrative expense increased $22.9 million, or 58%, because of an increase of $17.4 million in non-cash incentive compensation and increased expenses from Company growth. Excluding incentive compensation, general and administrative expense per Mcfe remained unchanged at $0.15.

The decrease in derivative fair value gain, from $54.4 million in 2001 to $2.6 million in 2002, is primarily because of significant gains related to call options and the Enron Btu swap contract in 2001. See Note 7 to Consolidated Financial Statements.

Interest expense decreased $2 million, or 4%, primarily because of an 18% decrease in the weighted average interest rate, partially offset by a 13% increase in weighted average borrowings related to property acquisitions and by decreased capitalized interest. Interest expense per Mcfe decreased 17% from $0.29 in 2001 to $0.24 in 2002. In 2002, we also recognized an $8.5 million loss on extinguishment of debt related to the redemption of our 9¼% senior subordinated notes and a partial purchase and cancellation of our 8¾% senior subordinated notes. See Note 3 to Consolidated Financial Statements.

Liquidity and Capital Resources

Our primary sources of liquidity are cash flow from operating activities, borrowings against the revolving credit facility, occasional producing property sales (including sales of royalty trust units) and public offerings of equity and debt. Other than for operations, our cash requirements are generally for the acquisition, exploration and development of oil and gas properties, and debt and dividend payments. Exploration and development expenditures and dividend payments have generally been funded by cash flow from operations. We believe that our sources of liquidity are adequate to fund our cash requirements in 2004.

Cash provided by operating activities was $794.2 million in 2003, compared with cash provided by operating activities of $490.8 million in 2002 and $542.6 million in 2001. Increased cash provided by operating activities from 2002 to 2003 was primarily because of increased prices and production from acquisitions and development activity, while decreased cash provided by operating activities from 2001 to 2002 was primarily because of decreased prices. Cash flow from operating activities was increased by changes in operating assets and liabilities of $3.7 million in 2003, and was decreased by changes in operating assets and liabilities of $22.9 million in 2002 and $1.5 million in 2001. Changes in operating assets and liabilities are primarily the result of timing of cash receipts and disbursements. Cash flow from operating activities was also reduced by exploration expense of $1.8 million in 2003, $2.2 million in 2002 and $5.4 million in 2001. Cash flow from operating activities is largely dependent upon the prices received for oil and gas production. We have hedged approximately half of our projected 2004 gas production. See "Product Prices" under "Significant Events, Transactions and Conditions" above.

We do not have any investments in unconsolidated entities or persons that could materially affect the liquidity or the availability of capital resources.

Financial Condition

Total assets increased 36% from $2.6 billion at December 31, 2002 to $3.6 billion at December 31, 2003, primarily because of Company growth related to acquisitions and development. As of December 31, 2003, total capitalization was $2.7 billion, of which 46% was long-term debt. Capitalization at December 31, 2002 was $2 billion of which 55% was long-term debt. The decrease in the debt-to-capitalization ratio from year-end 2002 to 2003 is primarily because of our common stock offering in April 2003 and earnings for the year.

Working Capital

We generally maintain low cash and cash equivalent balances because we use available funds to reduce bank debt. Short-term liquidity needs are satisfied by bank commitments under the loan agreement (see "Financing" below). Because of this, and since our principal source of operating cash flows (i.e., proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. Working capital decreased from a negative position of $41.1 million at December 31, 2002 to negative working capital of $59.4 million at December 31, 2003. Excluding the effects of current derivative and deferred tax current assets and liabilities, working capital decreased $20.1 million. This decrease is because of increased accounts payable and accrued liabilities primarily related to increased production and drilling liabilities, partially offset by increased revenues. Any cash settlement of hedge derivatives should generally be offset by increased or decreased cash flows from our sales of related production. Therefore, we believe that most of the changes in derivative fair value assets and liabilities are offset by changes in value of our oil and gas reserves. This offsetting change in value of oil and gas reserves, however, is not recorded in the financial statements.

None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date. When the monthly cash settlement amount under our hedge derivatives is calculated, if market prices are higher than the fixed contract prices, we are required to pay the contract counterparties. While this payment will ultimately be funded by higher prices received from sale of our production, production receipts lag payments to the counterparties by as much as six weeks. Any interim cash needs are funded by borrowings under our revolving credit agreement.

Most of our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. Because of declining credit ratings of some of our customers, we have greater concentrations of credit with a few large integrated energy companies with investment grade ratings. Financial and commodity-based futures and swap contracts expose us to credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions. Letters of credit or other appropriate forms of security are obtained as considered necessary to limit risk of loss.

Financing

On December 31, 2003, borrowings under the revolving credit agreement with commercial banks were $502 million with unused borrowing capacity of $298 million. The interest rate of 2.54% at December 31, 2003 is based on the one-month London Interbank Offered Rate ("LIBOR") plus 1.375%. In February 2004, we replaced our revolving credit agreement with a new five-year revolving credit agreement with commercial banks that matures in February 2009. The new agreement provides for an initial commitment amount of $800 million, which may be increased to a maximum of $1 billion, and an interest rate based on the LIBOR plus 1%. The agreement requires us to maintain a debt-to-total capitalization ratio of not more than 60%.

In September 2003, Moody's assigned to the Company an SGL-1 liquidity rating, its highest rating. In January 2004, Standard & Poors upgraded our corporate credit rating to an investment grade and all liens on producing properties and other collateral were irrevocably released as security for our revolving credit facility. As a result, Moody's upgraded our existing senior notes to Ba1 from Ba2 and confirmed our Ba1 senior implied rating. Our Standard & Poors corporate credit rating is BBB- and our Moody's credit rating is Ba1. None of our debt agreements have payment acceleration provisions in the event of a decline in our credit ratings.

In June 2003, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities, preferred stock, common stock or warrants to purchase debt or stock. The total face amount of securities that can be offered is $1 billion, at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities will be used for general corporate purposes, including reduction of bank debt. In January 2004, we sold $500 million of 4.9% senior notes under the shelf agreement, after which $500 million remains available for future sales of securities. See Note 3 to Consolidated Financial Statements.

Capital Expenditures

In 2003, exploration and development cash expenditures totaled $461.6 million compared with $372.7 million in 2002. We have budgeted $520 million for the 2004 development and exploration program. As we have done historically, we expect to fund the 2004 development program with cash flow from operations. Since there are no material long-term commitments associated with this budget, we have the flexibility to adjust our actual development expenditures in response to changes in product prices, industry conditions and the effects of our acquisition and development programs.

The weak U.S. dollar, raw material shortages and strong demand for steel in China and Europe have tightened worldwide steel supplies, causing prices to rise by more than 50% since November 2003. In response, we have increased our tubular inventory and are currently negotiating contracts with our vendors to support our development program. Should steel prices continue to escalate, our development budget could rise by as much as 10%. While we expect to acquire adequate supplies to complete our development program, a further tightening of steel supplies could restrain the program, limiting our production growth.

Our 2004 acquisitions budget is $650 million, including $243 million of acquisitions in January 2004 and $200 million expected to close in April 2004. We plan to fund future 2004 property acquisitions with cash flow from operations and bank or public debt. If our 2004 acquisitions exceed $650 million, we expect to fund a portion of our acquisitions with publicly placed equity securities. There are no restrictions under our revolving credit agreement that would affect our ability to use our remaining borrowing capacity for acquisitions of producing properties.

To date, we have not spent significant amounts to comply with environmental or safety regulations, and we do not expect to do so during 2004. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Dividends

The Board of Directors has historically declared quarterly dividends of $0.01 per outstanding share. As adjusted for stock splits, the Board declared quarterly dividends of $0.004 per common share for the first quarter 2001, $0.006 per common share each quarter for the remainder of 2001 and 2002 and $0.008 per common share for each quarter of 2003. In August 2003, the Board also declared a dividend of 0.0059 units of Cross Timbers Royalty Trust for each share of our common stock outstanding on September 2, 2003. The market value at the date of distribution was approximately $0.12 per common share. In February 2004, the Board of Directors declared a five-for-four stock split to be effected on March 17, 2004, as well as a first quarter 2004 dividend of $0.01 per common share. Because of the five-for-four stock split, this represents a 25% increase in our dividend rate. Our ability to pay dividends is dependent upon available cash flow, as well as other factors. Although there is a cumulative maximum restriction on distributions to common stockholders under our 7½% senior note and 6¼% senior note covenants, because of retained and projected future earnings, we do not anticipate these restrictions will affect future dividend payments.

Income Taxes

As of December 31, 2003, we had estimated tax loss carryforwards of approximately $242 million, of which $1 million are related to capital losses. The capital loss carryforwards expire in 2004, while the remaining ordinary loss carryforwards are scheduled to expire in 2010 through 2023. Approximately $22 million of the tax loss carryforwards are the result of acquisitions. We have not booked any valuation allowance because we believe we have tax planning strategies available to realize our tax loss carryforwards.

Contractual Obligations and Commitments

The following summarizes our significant obligations and commitments to make future contractual payments as of December 31, 2003. We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt or losses.

		Payments Due by Year					
(in thousands)	Total	2004	2005	2006	2007	2008	After 2008
Long-term debt	$1,252,000	$ -	$ -	$ -	$ -	$ -	$1,252,000
Operating leases	126,919	23,343	20,522	15,712	14,788	14,248	38,306
Drilling contracts	45,223	45,223	-	-	-	-	-
Transportation contracts	146,193	12,982	19,928	20,490	19,591	18,804	54,398
Derivative contract liabilities at December 31, 2003 fair value	114,697	96,653	7,643	10,401	-	-	-
Total	$1,685,032	$178,201	$ 48,093	$ 46,603	$ 34,379	$ 33,052	$1,344,704

Long-Term Debt. At December 31, 2003, borrowings were $502 million under our senior bank revolving credit facility due in May 2005. In February 2004, we fully repaid this facility and entered a new five-year revolving credit agreement with commercial banks that matures in February 2009, as reflected in the table above. Our senior notes, totaling $750 million at December 31, 2003, are due in 2012 and 2013. In January 2004, we sold $500 million of 4.9% senior notes which are due in February 2014. For further information regarding long-term debt, see Note 3 to Consolidated Financial Statements.

Transportation Contracts. We have entered firm transportation contracts with various pipelines. Under these contracts we are obligated to transport minimum daily gas volumes or pay for any deficiencies at a specified reservation fee rate. As calculated on a monthly basis, our failure to deliver these minimum volumes to the pipeline requires us to pay the pipeline for any deficiency. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under these firm transportation contracts, therefore avoiding payment for deficiencies.

Derivative Contracts. We have entered into futures contracts and swaps to hedge our exposure to oil and natural gas price fluctuations. As of December 31, 2003, market prices generally exceeded the fixed prices specified by these contracts, resulting in a derivative fair value current liability of $96.7 million and long-term liability of $18.0 million. If market prices are higher than the contract prices when the cash settlement amount is calculated, we are required to pay the contract counterparties. While such payments will be funded by higher prices received from the sale of our production, production receipts may be received as much as six weeks after payment to counterparties and can result in draws on our revolving credit facility. See Note 8 to Consolidated Financial Statements.

Post-Retirement Plans

We have a retiree medical plan that provides retired employees and directors with health care benefits similar to those provided employees. Employees may qualify as a retiree with any combination of age and qualified years of service that total 60, with a minimum age of 45 and a minimum of five years full-time service. Directors are eligible to receive benefits when their combined age and years of service on the Board totals 60, with a minimum age of 45 and a minimum of five years of service. Otherwise, retirement benefits are only provided through our defined contribution 401(k) plan. Post-retirement medical benefits are not prefunded, but are paid when incurred. Our periodic benefit cost recorded for 2003 was $1.8 million. Future benefit costs will be affected by fluctuations in interest rates and health care cost trends. We do not currently anticipate that retiree medical plan costs will be significant in relation to the Company's future financial position, results of operations or cash flows.

Related Party Transactions

We have limited related party transactions, as further disclosed in Note 2 to Consolidated Financial Statements. In February 2004, our Board of Directors approved an agreement with a firm, partially owned by one of our directors, to establish fees that will be paid in connection with any advisory services the firm provides for up to $800 million in future acquisitions. The agreement is effective as of November 2003. For the first acquisition, we will pay a fee of $250,000 plus a transaction fee equal to 0.75% of the purchase price. For any subsequent acquisition closing, we will pay only the transaction fee. The initial term of the agreement expires December 31, 2004. To date, we have not paid the director-related company any amounts under this agreement. This same director-related company represented the seller of properties for acquisitions totaling approximately $186 million that we closed in January 2004.

In connection with our sale of properties in 1999, the same director-related Company represented the purchaser and also invested in the purchase. We invested $584,000 in a limited partnership that purchased a small interest in these properties. Based on an impairment evaluation in 2003, we have written down this investment to $100,000.

During 2002, the same director-related company performed consulting services in connection with our acquisition of properties in East Texas, Louisiana and the San Juan Basin of New Mexico. See Note 13 to Consolidated Financial Statements. The director-related company received a fee of $2.4 million for these services, which was 1% of the total of the property purchase price and the related exchange transaction value.

The same director-related company performed consulting services in connection with a 1998 acquisition and was entitled to receive, at its election, either a 20% working interest or a 1% overriding royalty interest conveyed from our 100% working interest in the properties after payout of acquisition and operating costs. The Board of Directors authorized the purchase of this potential interest from the director-related company and other parties in November 2001 for $15 million, as supported by a third-party fairness opinion. The director-related company received $10 million of the total purchase price.

Critical Accounting Policies

Our financial position and results of operations are significantly affected by accounting policies and estimates related to our oil and gas properties, proved reserves, asset retirement obligation and commodity prices and risk management, as summarized below.

Oil and Gas Property Accounting

Oil and gas exploration and production companies may elect to account for their property costs using either the "successful efforts" or "full cost" accounting method. Under the successful efforts method, unsuccessful exploratory well costs, as well as all exploratory geological and geophysical costs, are expensed. Under the full cost method, all exploration costs are capitalized, regardless of success. Selection of the oil and gas accounting method can have a significant impact on a company's financial results. We use the successful efforts method of accounting and generally pursue acquisitions and development of proved reserves as opposed to exploration activities.

Property costs that exceed management's estimate of future cash flows of proved reserves must be expensed through an impairment provision. We evaluate possible impairment of producing properties, generally aggregated on a field-level basis, when conditions indicate that they may be impaired. Cash flow pricing estimates are based on existing proved reserve and production information and pricing assumptions that management believes are reasonable. Individually significant undeveloped properties are reviewed for impairment on a property-by-property basis, and impairment of other undeveloped properties is done on a total basis. Our impairment of producing properties has been limited to a $2 million provision recorded in 1998. Our impairment provisions have been limited, and we do not expect significant impairment provisions in the near future, because of our relatively low acquisition and development costs compared with expected product prices. By comparison, full cost companies must record impairment under a "ceiling test" which is computed on an aggregate country basis using discounted estimated future after-tax cash flows based on current market prices. This generally results in more frequent and higher impairment provisions under the full cost method when prices decline significantly.

Oil and Gas Reserves

Our 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 previous estimates.

Proved reserves, as defined by the Financial Accounting Standards Board and adopted by the Securities and Exchange Commission, are limited to reservoir areas that indicate economic producibility through actual production or conclusive formation tests, and generally cannot extend beyond the immediately adjoining undrilled portion. Although improved technology often can identify possible or probable reserves other than by drilling, these reserves cannot be estimated and disclosed.

Depreciation, depletion and amortization of producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. If estimated proved reserves decline, future DD&A expense will increase and net income will be reduced. A decline in proved reserves also can result in a required impairment provision, as discussed under "Oil and Gas Property Accounting" above.

The standardized measure of discounted future net cash flows and changes in such cash flows, as reported in Note 16 to Consolidated Financial Statements, are 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 could have a significant impact on the standardized measure. Accordingly, the standardized measure does not represent management's estimated current market value of proved reserves.

Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties (including removal of our offshore platforms in Alaska) at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our wells, the costs to ultimately retire our wells may vary significantly from previous estimates.

Commodity Prices and Risk Management

Commodity prices significantly affect our operating results, financial condition, cash flows and ability to borrow funds. Current market oil and gas prices are affected by supply and demand as well as seasonal, political and other conditions which we generally cannot control. Oil and gas prices and markets are expected to continue their historical volatility. See "Significant Events, Transactions and Conditions – Product Prices" above.

We attempt to reduce our price risk by entering into financial instruments such as futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts. While these instruments secure a certain price and, therefore, a certain cash flow, there is the risk that we will not be able to realize the benefit of rising prices. These contracts also expose us to credit risk of nonperformance by the contract counterparties, all of which are major investment grade financial institutions. We attempt to limit our credit risk by obtaining letters of credit or other appropriate forms of security. We also have sold call options as part of our hedging program. Call options, however, do not provide a hedge against declining prices, and there is the risk that the call sales proceeds will be less than the benefit a higher sales price would have provided.

While our price risk management activities decrease the volatility of cash flows, they may obscure our operating results and financial condition. As required under generally accepted accounting principles, we adopted SFAS No. 133 on January 1, 2001 with a significant charge to our income statement and equity related to recording derivative financial instruments at their market value. Subsequent to that date, we recorded significant derivative fair value gains in the 2001 income statement and equity related to decline in natural gas prices. In each instance, these are projected gains and losses to be realized upon settlement of these contracts in subsequent periods when related production occurs. These gains and losses are generally offset by increases and decreases in the market value of our proved reserves, which are not reflected in the financial statements. Derivatives that provide effective cash flow hedges are designated as hedges, and, to the extent the hedge is determined to be effective, we defer related unrealized fair value gains and losses in accumulated other comprehensive income until the hedged transaction occurs. Because hedge accounting is not required under generally accepted accounting principles, our operating results as reflected in our financial statements may not be comparable to other companies.

See Item 7A, "Commodity Price Risk" for the effect of price changes on derivative fair value gains and losses.

Accounting Pronouncements

An issue within the oil and gas industry has recently arisen regarding whether SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, require costs associated with mineral rights be accounted for and separately reported on the balance sheet as intangible assets. As is the common practice in the oil and gas industry, we include leasehold acquisition costs as a component of both producing properties and undeveloped properties on our consolidated balance sheets. This question of SFAS No. 141 and SFAS No. 142 applicability has been referred to the Financial Accounting Standards Board. If it is ultimately determined that SFAS No. 141 and SFAS No. 142 require intangible asset accounting treatment for costs associated with mineral rights, the following amounts would be reclassified on the consolidated balance sheets from producing properties, undeveloped properties and accumulated depreciation, depletion and amortization:

(in thousands)	December 31	
	2003	2002
Intangible Assets:		
Producing property leasehold acquisition costs	$2,093,318	$1,542,343
Undeveloped property leasehold acquisition costs	12,627	12,163
Total leasehold acquisition costs	2,105,945	1,554,506
Accumulated depletion	(438,151)	(336,374)
Net leasehold acquisition costs	$1,667,794	$1,218,132

Accounting for the costs of mineral rights as intangible assets under SFAS No. 141 and SFAS No. 142 would also require additional financial statement disclosures but would not affect our method of amortization or assessment of impairment. Therefore, any resulting accounting change would have no effect on our consolidated income statements or statements of cash flows.

In May 2003, the Financial Accounting Standards Board issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. Such financial instruments include mandatorily redeemable shares of stock, obligations to repurchase the issuer's equity shares and obligations that an issuer may settle by issuing a variable number of its equity shares. The Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. In November 2003, the effective date for SFAS No. 150 was deferred for provisions relating to certain financial instruments issued by consolidated subsidiaries. None of our consolidated entities currently have any of these financial instruments, and we do not anticipate SFAS No. 150 will have a material effect on future financial position or earnings.

In December 2003, the Financial Accounting Standards Board issued a revision of Interpretation No. 46 to clarify consolidation requirements for variable interest entities. We do not anticipate this interpretation to have an effect on our financial statements since we do not have interests in variable interest entities.

Also in December 2003, the Financial Accounting Standards Board issued SFAS No. 132, revising disclosures required about pensions and other post-retirement benefits. These revised disclosures are included in Note 12 to Consolidated Financial Statements for our post-retirement health plan. In accordance with a deferred effective date, future annual reporting will disclose future plan benefit payments expected to be paid for each of the five years following the latest balance sheet date and in the aggregate for the following five years.

In January 2004, the Financial Accounting Standards Board issued Staff Position No. 106-1 regarding treatment in post-retirement health plan accounting and disclosures for the effects of the Medicare Prescription Drug, Improvement and Modernization Act, which was signed by the President into law in December 2003. Because our post-retirement health plan does not provide prescription drug coverage beyond the date of eligibility for Medicare coverage, this change in Medicare coverage does not impact estimates for our benefit costs.

Production Imbalances

We have gas production imbalance positions that are the result of partial interest owners selling more or less than their proportionate share of gas on jointly owned wells. Imbalances are generally settled by disproportionate gas sales over the remaining life of the well, or by cash payment by the overproduced party to the underproduced party. We use the entitlement method of accounting for natural gas sales. Accordingly, revenue is deferred for gas deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. The consolidated balance sheets include the following amounts related to production imbalances:

	December 31			
(in thousands)	2003		2002	
	Amount	Mcf	Amount	Mcf
Accounts receivable - current underproduction	$ 23,949	7,135	$ 17,248	6,178
Accounts payable - current overproduction	(19,366)	(5,900)	(14,381)	(5,165)
Net current gas underproduction balancing receivable	$ 4,583	1,235	$ 2,867	1,013
Other assets - noncurrent underproduction	$ 19,385	6,148	$ 14,934	5,642
Other long-term liabilities - noncurrent overproduction	(29,776)	(9,353)	(23,027)	(8,492)
Net long-term gas overproduction balancing payable	(10,391)	(3,205)	(8,093)	(2,850)
Other assets - carbon dioxide underproduction	1,977	12,354	1,868	11,675
Net long-term overproduction balancing payable	$ (8,414)		$ (6,225)	

Forward-Looking Statements

Certain information included in this annual report and other materials filed or to be filed by us with the Securities and Exchange Commission, as well as information included in oral statements or other written statements made or to be made by us, contain projections and 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 our operations and the oil and gas industry. Such forward-looking statements may be or may concern, among other things, capital expenditures, cash flow, drilling activity, drilling locations, acquisition and development activities, production and reserve growth, pricing differentials, reserve potential, operating costs, operating margins, production activities, oil, gas and natural gas liquids reserves and prices, hedging activities and the results thereof, liquidity, debt repayment, regulatory matters and competition. Such forward-looking statements are based on management's current plans, expectations, assumptions, projections and estimates and are identified by words such as "expects," "intends," "plans," "projects," "predicts," "anticipates," "believes," "estimates," "goal," "should," "could," "assume," 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, forecasted in, or implied in such forward-looking statements. Some of the risk factors that could cause actual results to differ materially are discussed below.

Oil and Gas Price Fluctuations. Our results of operations depend upon the prices we receive for our oil and gas. Historically, the markets for oil and gas have been volatile and are likely to remain volatile in the future. We routinely hedge a portion of our production to reduce the effects of price volatility (see "Hedging Arrangements" below). Otherwise, the prices we receive depend upon factors beyond our control, including political instability in oil-producing regions, weather conditions, ability of OPEC to agree upon and maintain oil prices and production levels, consumer demand, worldwide economic conditions and the price and availability of alternative fuels. Moreover, government regulations, such as regulation of gas transportation and price controls, can affect product prices in the long term. These external factors and the volatile nature of the energy markets make it difficult to reliably estimate future prices of oil and gas. To the extent we have not hedged our production, any decline in oil and gas prices adversely affects our financial condition. If the oil and gas industry experiences significant price declines, we may, among other things, be unable to meet our financial obligations or make planned capital expenditures.

Debt Level. We have substantial debt and may incur more. If we are unsuccessful in increasing production from existing reserves or developing new reserves, we may lack the funds to pay principal and interest on our debt obligations. Our indebtedness also affects our ability to finance future operations and capital needs and may preclude pursuit of other business opportunities.

Capital Requirements. We make, and will continue to make, substantial capital expenditures for the acquisition, development, production, exploration and abandonment of our oil and gas reserves. We intend to finance our capital expenditures primarily through cash flow from operations, bank borrowings and public offerings of equity and debt. Lower oil and gas prices, however, may reduce cash flow available to pay down bank borrowings or other debt.

Competitive Industry. The oil and gas industry is highly competitive. We compete with major oil companies, independent oil and gas businesses, and individual producers and operators. In addition, there is competition from alternative energy sources, such as heating oil, imported liquified natural gas and other fossil fuels. Many of our competitors have financial, technological and other resources substantially greater than ours. These companies may be able to pay more for development prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to develop and exploit our oil and gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

Reserve Replacement. Our success depends upon finding, acquiring and developing oil and gas reserves that are economically recoverable. Unless we are able to successfully explore for, develop or acquire proved reserves, our proved reserves will decline through depletion and our financial assets and annual revenues will decline unless prices substantially increase. We cannot assure the success of our exploration, development and acquisition activities.

Hedging Arrangements. To reduce our exposure to fluctuations in the prices of oil and gas, we currently and may in the future enter into hedging arrangements for a portion of our oil and gas production. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, the counterparty to the hedging contract defaults on its contract obligations, or there is a change in the expected differential between the underlying price in the hedging agreements and actual prices received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for oil and gas.

Reserve Estimates. Estimating our proved reserves involves many uncertainties, including factors beyond our control. Petroleum engineers consider many factors and make assumptions in estimating oil and gas reserves and future net cash flows. Lower oil and gas prices generally cause lower estimates of proved reserves. Ultimately, actual production, revenues and expenditures relating to our reserves will vary from any estimates, and these variations may be material.

Acquiring Producing Properties. We constantly evaluate opportunities to acquire oil and gas properties and frequently engage in bidding and negotiation for these acquisitions. If successful in this process, we may alter or increase our capitalization through the issuance of additional debt or equity securities, the sale of production payments or other measures. Any change in capitalization affects our risk profile. Acquisitions may also alter the nature of our business. This could occur when the character of acquired properties is substantially different from our existing properties in terms of operating or geologic characteristics.

Drilling Activities. Our drilling activities subject us to many risks, including the risk that we will not find commercially productive reservoirs. Drilling for oil and gas can be unprofitable, not only from dry wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements and shortages or delays in the delivery of equipment and services can delay our drilling operations or result in their cancellation. Shortages of equipment, including pipe, can lead to a delay or suspension of drilling and can significantly increase the cost of drilling. The cost of drilling, completing and operating wells is often uncertain, and we cannot assure that new wells will be productive or that we will recover all or any portion of our investment.

Marketability of Production. The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities could harm our business. We deliver some of our oil and gas through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future.

Growth through Acquisitions. Our business strategy has emphasized growth through strategic acquisitions, but we may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our growth strategy may be hindered if we are not able to obtain financing or regulatory approvals. Our ability to grow through acquisitions and manage growth will require us to continue to invest in operational, financial and management information systems and to attract, retain, motivate and effectively manage our employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Government Regulations. Extensive federal, state and local regulation of the oil and gas industry significantly affects our operations. In particular, our oil and gas exploration, development and production, and our storage and transportation of liquid hydrocarbons, are subject to stringent environmental regulations. These regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning oil and gas wells and other related facilities. These regulations may become more demanding in the future. We may need to expend significant financial and managerial resources to comply with environmental regulations and permitting requirements. Although we believe that our operations generally comply with applicable laws and regulations, we may incur substantial additional costs and liabilities in our operations as a result of stricter environmental laws, regulations and enforcement policies.

Operating Hazards and Uninsured Risks. Our operations are subject to inherent hazards and risks, such as fire, explosions, blowouts, formations with abnormal pressures, uncontrollable flows of underground gas, oil and formation water and environmental hazards such as gas leaks and oil spills. Any of these events could cause a loss of hydrocarbons, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations, personal injury claims, loss of life, damage to our properties, or damage to the property of others. In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease or by acquired companies prior to the date we acquire them. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all environmental damages that could occur is available at a reasonable cost. We believe that our insurance is adequate and customary for companies of similar size and operation, but losses could occur for uninsured risks or in amounts exceeding existing coverage. The occurrence of an event that is not fully covered by insurance could adversely affect our financial condition and results of operations.

Item 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

We only enter derivative financial instruments in conjunction with our hedging activities. These instruments principally include commodity futures, collars, swaps and option agreements and interest rate swap agreements. These financial and commodity-based derivative contracts are used to limit the risks of fluctuations in interest rates and natural gas and crude oil prices. Gains and losses on these derivatives are generally offset by losses and gains on the respective hedged exposures.

Our Board of Directors has adopted a policy governing the use of derivative instruments, which requires that all derivatives used by us relate to an underlying, offsetting position, anticipated transaction or firm commitment, and prohibits the use of speculative, highly complex or leveraged derivatives. The policy also requires review and approval by the Chairman, the Executive Vice President - Administration and the Senior Vice President - Marketing of all risk management programs using derivatives and all derivative transactions. These programs are also reviewed at least quarterly by our internal risk management committee and annually by the Board of Directors.

Hypothetical changes in interest rates and prices chosen for the following estimated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Interest Rate Risk

We are exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At December 31, 2003, our variable rate debt had a carrying value of $502 million, which approximated its fair value, and our fixed rate debt had a carrying value of $750 million and an approximate fair value of $773.3 million. We attempt to balance the benefit of lower cost variable rate debt that has inherent increased risk with more expensive fixed rate debt that has less market risk. This is accomplished through a mix of bank debt with short-term variable rates and fixed rate senior and subordinated debt, as well as the occasional use of interest rate swaps.

The following table shows the carrying amount and fair value of long-term debt and the hypothetical change in fair value that would result from a 100-basis point change in interest rates. Unless otherwise noted, the hypothetical change in fair value could be a gain or a loss depending on whether interest rates increase or decrease.

(in thousands)	Carrying Amount	Fair Value *(a)*	Hypothetical Change in Fair Value
December 31, 2003			
Long-term debt	$ (1,252,000)	$ (1,275,285)	$ 51,085
December 31, 2002			
Long-term debt	$ (1,118,170)	$ (1,146,572)	$ 29,264

(a) Fair value is based upon current market quotes and is the estimated amount required to purchase our long-term debt on the open market. This estimated value does not include any redemption premium.

Commodity Price Risk

We hedge a portion of our price risks associated with our crude oil and natural gas sales. As of December 31, 2003, we had outstanding gas futures contracts, swap agreements and gas basis swap agreements. These contracts and agreements had a net fair value loss of approximately $84.7 million at December 31, 2003 and a net fair value loss of $93.7 million at December 31, 2002. Of the December 31, 2003 fair value, a $91.6 million loss has been determined based on the exchange-trade value of NYMEX contracts and a $6.9 million gain has been determined based on the broker bid and ask quotes for basis contracts. These fair values approximate amounts confirmed by the counterparties. As of December 31, 2003, we had no outstanding oil futures contracts and differential swaps. The aggregate effect of a hypothetical 10% change in gas prices would result in a change of approximately $63.5 million in the fair value of gas futures contracts and swap agreements at December 31, 2003. None of our derivative contracts have margin requirements or collateral provisions which could require funding prior to the scheduled cash settlement date. See Note 8 to Consolidated Financial Statements.

Because most of our futures contracts and swap agreements have been designated as hedge derivatives, changes in their fair value generally are reported as a component of accumulated other comprehensive income until the related sale of production occurs. At that time, the realized hedge derivative gain or loss is transferred to product revenues in the consolidated income statement.

We had a physical delivery contract to sell 35,500 Mcf per day from 2002 through July 2005 at a price of approximately 10% of the average NYMEX futures price for intermediate crude oil. Because this gas sales contract was priced based on crude oil, which is not clearly and closely associated with natural gas prices, it was accounted for as a non-hedge derivative financial instrument. This contract (referred to as the Enron Btu swap contract) was terminated in December 2001 in conjunction with the bankruptcy filing of Enron Corporation. In November 2001, we entered derivative contracts to effectively defer until 2005 and 2006 any cash flow impact related to 25,000 Mcf of daily gas deliveries in 2002 that were to be made under the Enron Btu swap contract. The net fair value loss on these contracts at December 31, 2003 was $18 million. The effect of a hypothetical 10% change in gas prices would result in a change of approximately $4.2 million in the fair value of these contracts, while a 10% change in crude oil prices would result in a change of approximately $2.4 million.

Item 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

The following financial statements and supplementary information are included under Item 15(a):

Item 9. ***CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE***

On May 20, 2002, we appointed KPMG LLP as independent auditors for fiscal 2002 to replace Arthur Andersen LLP effective with such appointment. The change in independent auditors was approved by the Board of Directors upon the recommendation of the Audit Committee. Information regarding this change in independent auditors is included in our current report on Form 8-K dated May 20, 2002.

There have been no other changes in accountants or any disagreements with accountants on any matter of accounting principles or practices or financial statement disclosures during the two years ended December 31, 2003 and 2002.

Item 9A. ***CONTROLS AND PROCEDURES***

We performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15 and 15d-15 as of the end of the period covered by this report. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in our periodic filings with the Securities and Exchange Commission.

There have been no significant changes in our internal controls or in other factors that could affect these controls subsequent to the date of their evaluation.

PART III

Except for the portion of Item 10 relating to Executive Officers of the Registrant which is included in Part I of this Report and is included below, the information called for by Items 10 through 14 is incorporated by reference to the Company's Notice of Annual Meeting and Proxy Statement to be filed with the Securities and Exchange Commission no later than April 30, 2004.

Item 10. *DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT*

We have a Code of Business Conduct and Ethics that applies to all directors, officers and employees, including the chief executive officer and senior financial officers. We also have a Code of Ethics for the Chief Executive Officer and Senior Financial Officers. You can find our Code of Business Conduct and Ethics and our Code of Ethics for the Chief Executive Officer and Senior Financial Officers on our web site at http://www.xtoenergy.com.

Our Board of Directors has adopted Corporate Governance Guidelines and charters for the Audit Committee, Compensation Committee and the Corporate Governance and Nominating Committee. You can find these documents on our web site at http://www.xtoenergy.com. You can also obtain a free copy of any of the materials referred to above by contacting us at 810 Houston Street, Fort Worth, Texas 76102, Attn: Corporate Secretary.

Item 11. *EXECUTIVE COMPENSATION*

Item 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT*

Item 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS*

Item 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

PART IV

Item 15. ***EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K***

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

All other financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to consolidated financial statements.

(b) Reports on Form 8-K

We filed the following reports on Form 8-K during the quarter ended December 31, 2003 and through March 15, 2004:

On October 16, 2003, we filed a report on Form 8-K dated October 15, 2003, to announce the acquisition of properties in East Texas and the Arkoma and San Juan basins.

On January 8, 2004, we filed a report on Form 8-K dated January 8, 2004 to announce we entered an agreement to purchase properties in East Texas and northern Louisiana, and that our Board of Directors approved a $500 million development and exploration budget for 2004.

On January 14, 2004, we filed a report on Form 8-K dated January 14, 2004 to report the filing of a preliminary prospectus supplement and provided exhibits to the Prospectus, dated July 7, 2003.

On January 16, 2004, we filed a report on Form 8-K dated January 16, 2004 to report the filing of a prospectus supplement and provided exhibits to the Prospectus, dated July 7, 2003.

On February 2, 2004, we filed a report on Form 8-K dated January 30, 2004 to announce the completion of previously announced purchases of East Texas and northern Louisiana producing properties.

On February 24, 2004, we filed a report on Form 8-K dated February 19, 2004 to announce the appointment of a new Director and that we entered definitive agreements with multiple parties to acquire producing properties located primarily in the Barnett Shale of North Texas and in the Arkoma Basin for a total of $200 million.

We have furnished two reports on Form 8-K under Item 12 during this time period.

(c) Exhibits

See Index to Exhibits at page 81 for a description of the exhibits filed as a part of this report. Documents filed prior to June 1, 2001, were filed with the Securities and Exchange Commission under our prior name, Cross Timbers Oil Company.

XTO ENERGY INC.
Consolidated Balance Sheets

(in thousands, except shares)	December 31 2003	December 31 2002
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 6,995	$ 14,954
Accounts receivable, net	193,666	145,356
Derivative fair value	11,351	40,628
Current income tax receivable	4,503	-
Deferred income tax benefit	32,455	32,680
Other	12,193	11,172
Total Current Assets	261,163	244,790
Property and Equipment, at cost – successful efforts method:		
Producing properties	4,253,221	3,081,488
Undeveloped properties	12,627	12,163
Other	70,494	51,861
Total Property and Equipment	4,336,342	3,145,512
Accumulated depreciation, depletion and amortization	(1,024,275)	(774,547)
Net Property and Equipment	3,312,067	2,370,965
Other Assets:		
Derivative fair value	646	1,032
Other	37,258	31,406
Total Other Assets	37,904	32,438
TOTAL ASSETS	$ 3,611,134	$ 2,648,193
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 218,710	$ 150,107
Payable to royalty trusts	4,848	6,466
Derivative fair value	96,653	128,001
Current income taxes payable	-	517
Other	346	805
Total Current Liabilities	320,557	285,896
Long-term Debt	1,252,000	1,118,170
Other Long-term Liabilities:		
Derivative fair value	18,044	22,953
Deferred income taxes payable	426,730	286,472
Asset retirement obligation	93,379	-
Other	34,782	26,916
Total Other Long-term Liabilities	572,935	336,341
Commitments and Contingencies (Note 6)		
Stockholders' Equity:		
Common stock ($.01 par value, 250,000,000 shares authorized, 234,251,352 and 226,224,970 shares issued)	2,343	2,262
Additional paid-in capital	753,900	533,902
Treasury stock, at cost (-0- and 14,596,856 shares)	-	(76,561)
Retained earnings	762,640	509,756
Accumulated other comprehensive income (loss)	(53,241)	(61,573)
Total Stockholders' Equity	1,465,642	907,786
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 3,611,134	$ 2,648,193

See accompanying notes to consolidated financial statements.

XTO ENERGY INC.
Consolidated Income Statements

(in thousands, except per share data)	Year Ended December 31		
	2003	2002	2001
REVENUES			
Gas and natural gas liquids	$ 1,040,370	$ 681,147	$ 710,348
Oil and condensate	135,058	115,324	116,939
Gas gathering, processing and marketing	12,982	11,622	12,832
Other	1,145	2,070	(1,371)
Total Revenues	1,189,555	810,163	838,748
EXPENSES			
Production	164,864	129,182	110,005
Taxes, transportation and other	104,654	57,225	63,656
Exploration	1,811	2,186	5,438
Depreciation, depletion and amortization	284,006	204,109	154,322
Accretion of discount in asset retirement obligation	5,330	-	-
Gas gathering and processing	9,350	9,114	9,522
General and administrative	107,675	62,114	39,217
Derivative fair value (gain) loss	10,201	(2,599)	(54,370)
Total Expenses	687,891	461,331	327,790
OPERATING INCOME	501,664	348,832	510,958
OTHER INCOME (EXPENSE)			
Gain on distribution of royalty trust units	16,216	-	-
Loss on extinguishment of debt	(9,601)	(8,528)	-
Interest expense, net	(63,769)	(53,555)	(55,601)
Total Other Expense	(57,154)	(62,083)	(55,601)
INCOME BEFORE INCOME TAX AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	444,510	286,749	455,357
INCOME TAX EXPENSE	158,009	100,690	161,952
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	286,501	186,059	293,405
Cumulative effect of accounting change, net of tax	1,778	-	(44,589)
NET INCOME	$ 288,279	$ 186,059	$ 248,816
EARNINGS PER COMMON SHARE			
Basic:			
Net income before cumulative effect of accounting change	$ 1.27	$ 0.89	$ 1.44
Cumulative effect of accounting change, net of tax	0.01	-	(0.22)
Net income	$ 1.28	$ 0.89	$ 1.22
Diluted:			
Net income before cumulative effect of accounting change	$ 1.26	$ 0.88	$ 1.41
Cumulative effect of accounting change, net of tax	0.01	-	(0.21)
Net income	$ 1.27	$ 0.88	$ 1.20
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	224,749	208,375	204,176

See accompanying notes to consolidated financial statements.

XTO ENERGY INC.
Consolidated Statements of Cash Flows

(in thousands)	Year Ended December 31		
	2003	2002	2001
OPERATING ACTIVITIES			
Net income	$ 288,279	$ 186,059	$ 248,816
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	284,006	204,109	154,322
Accretion of discount in asset retirement obligation	5,330	-	-
Non-cash incentive compensation	53,123	26,990	9,246
Deferred income tax	157,715	100,368	161,105
Gain on distribution of royalty trust units	(16,216)	-	-
Non-cash derivative fair value (gain) loss	10,771	6,890	(69,147)
Cumulative effect of accounting change, net of tax	(1,778)	-	44,589
Loss on extinguishment of debt	9,601	8,528	-
Non-cash settlement gain with Enron Corporation, and related revenue	-	(16,142)	-
Other non-cash items	(386)	(3,084)	(4,802)
Changes in operating assets and liabilities *(a)*	3,736	(22,876)	(1,514)
Cash Provided by Operating Activities	794,181	490,842	542,615
INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	-	149	319
Property acquisitions	(653,742)	(358,087)	(224,906)
Development costs	(459,762)	(370,558)	(381,026)
Other property and asset additions	(21,730)	(8,321)	(13,438)
Officer loan repayments	-	-	8,128
Cash Used by Investing Activities	(1,135,234)	(736,817)	(610,923)
FINANCING ACTIVITIES			
Proceeds from long-term debt	1,835,000	1,156,000	640,000
Payments on long-term debt	(1,701,170)	(893,830)	(553,000)
Net proceeds from common stock offering	247,972	-	-
Dividends	(6,640)	(4,984)	(4,413)
Senior note offering and debt costs	(7,797)	(8,381)	-
Proceeds from exercise of stock options and warrants	16,248	23,745	14,325
Payments upon exercise of stock options	(18,183)	(1,440)	(11,717)
Subordinated note redemption costs	(7,139)	(3,794)	-
Purchases of treasury stock and other	(25,197)	(13,197)	(17,515)
Cash Provided by Financing Activities	333,094	254,119	67,680
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(7,959)	8,144	(628)
Cash and Cash Equivalents, January 1	14,954	6,810	7,438
Cash and Cash Equivalents, December 31	$ 6,995	$ 14,954	$ 6,810

(a) **Changes in Operating Assets and Liabilities**

Accounts receivable	$ (49,628)	$ (19,088)	$ 58,706
Other current assets	(5,523)	2,758	(3,855)
Other operating assets	1,103	4,293	(1,738)
Enron Btu swap contract	-	(43,272)	-
Current liabilities	57,784	32,433	(54,627)
	$ 3,736	$ (22,876)	$ (1,514)

See accompanying notes to consolidated financial statements.

XTO ENERGY INC.
Consolidated Statements of Stockholders' Equity

(in thousands, except per share amounts)

	Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balances, December 31, 2000	$ 27,217	$ 2,065	$ 434,496	$ (50,829)	$ 84,418	$ -	$ 497,367
Net income	-	-	-	-	248,816	-	248,816
Cumulative effect of change in accounting for hedge derivatives, net of applicable income tax benefit of $36,251	-	-	-	-	-	(67,323)	(67,323)
Change in hedge derivative fair value, net of applicable income tax of $69,153	-	-	-	-	-	128,428	128,428
Hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of applicable income tax of $5,133	-	-	-	-	-	9,533	9,533
Comprehensive income							319,454
Issuance/vesting and forfeiture of performance shares	-	11	5,180	(4,226)	-	-	965
Stock option exercises, including income tax benefits	-	35	17,410	(410)	-	-	17,035
Treasury stock purchases	-	-	-	(9,249)	-	-	(9,249)
Common stock dividends ($0.0220 per share)	-	-	-	-	(4,522)	-	(4,522)
Preferred stock converted to common	(27,217)	89	27,128	-	-	-	-
Balances, December 31, 2001	-	2,200	484,214	(64,714)	328,712	70,638	821,050
Net income	-	-	-	-	186,059	-	186,059
Change in hedge derivative fair value, net of applicable income tax benefit of $51,543	-	-	-	-	-	(95,723)	(95,723)
Hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of applicable income tax benefit of $19,647	-	-	-	-	-	(36,488)	(36,488)
Comprehensive income							53,848
Issuance/vesting of performance shares	-	16	25,602	(10,276)	-	-	15,342
Stock option and warrant exercises, including income tax benefits	-	46	24,086	(35)	-	-	24,097
Treasury stock purchases	-	-	-	(1,536)	-	-	(1,536)
Common stock dividends ($0.0240 per share)	-	-	-	-	(5,015)	-	(5,015)
Balances, December 31, 2002	-	2,262	533,902	(76,561)	509,756	(61,573)	907,786
Net income	-	-	-	-	288,279	-	288,279
Change in hedge derivative fair value, net of applicable income tax benefit of $65,850	-	-	-	-	-	(122,293)	(122,293)
Hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of applicable income tax of $70,337	-	-	-	-	-	130,625	130,625
Comprehensive income							296,611
Issuance/vesting and forfeiture of performance shares	-	33	51,092	(23,124)	-	-	28,001
Stock option exercises, including income tax benefits	-	34	22,929	-	-	-	22,963
Treasury stock purchases	-	-	-	(2,296)	-	-	(2,296)
Common stock offering	-	173	247,799	-	-	-	247,972
Fair value of royalty trust unit distribution	-	-	-	-	(28,151)	-	(28,151)
Common stock dividends ($0.0320 per share)	-	-	-	-	(7,244)	-	(7,244)
Cancellation of treasury stock	-	(159)	(101,822)	101,981	-	-	-
Balances, December 31, 2003	$ -	$ 2,343	$ 753,900	$ -	$ 762,640	$ (53,241)	$ 1,465,642

See accompanying notes to consolidated financial statements.

1. Organization and Summary of Significant Accounting Policies

XTO Energy Inc., a Delaware corporation, was organized under the name Cross Timbers Oil Company in October 1990 to ultimately acquire the business and properties of predecessor entities that were created from 1986 through 1989. Cross Timbers Oil Company completed its initial public offering of common stock in May 1993 and changed its name to XTO Energy Inc. in June 2001.

The accompanying consolidated financial statements include the financial statements of XTO Energy Inc. and its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in the consolidation. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation.

All common stock shares and per share amounts in the accompanying financial statements have been adjusted for the five-for-four stock split to be effected March 17, 2004, the four-for-three stock split effected on March 18, 2003 and the three-for-two stock split effected on June 5, 2001.

We are an independent oil and gas company with production and exploration concentrated in Texas, Oklahoma, Arkansas, Kansas, New Mexico, Colorado, Wyoming, Alaska and Louisiana. We also gather, process and market gas, transport and market oil and conduct other activities directly related to our oil and gas producing activities.

Property and Equipment

We follow the successful efforts method of accounting, capitalizing costs of successful exploratory wells and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. A significant portion of the property costs reflected in the accompanying consolidated balance sheets are from acquisitions of producing properties from other oil and gas companies. Producing properties balances include costs of $80.6 million at December 31, 2003 and $62.4 million at December 31, 2002 related to wells in process of drilling, and $24.3 million at December 31, 2003 related to advance payments for acquisitions that subsequently closed. Inventory held for future use on our producing properties totaled $6.5 million at December 31, 2003 and $5.4 million at December 31, 2002, and is included in other current assets on the consolidated balance sheet.

Depreciation, depletion and amortization of producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. Other property and equipment is generally depreciated using the straight-line method over estimated useful lives which range from 3 to 40 years. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

If conditions indicate that long-term assets may be impaired, the carrying value of property is compared to management's future estimated pre-tax cash flow from properties generally aggregated on a field-level basis. If impairment is necessary, the asset carrying value is written down to fair value. Cash flow pricing estimates are based on existing proved reserve and production information and pricing assumptions that management believes are reasonable. Impairment of individually significant undeveloped properties is assessed on a property-by-property basis, and impairment of other undeveloped properties is assessed and amortized on an aggregate basis.

Asset Retirement Obligation

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 provides that, if the fair value for asset retirement obligation can be reasonably estimated, the liability should be recognized in the period when it is incurred. Oil and gas producing companies incur this liability upon acquiring or drilling a well. Under the method prescribed by SFAS No. 143, the retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to producing properties on the balance sheet. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. Prior to adoption of SFAS No. 143, we accrued for any estimated asset retirement obligation, net of estimated salvage value, as part of our calculation of depletion, depreciation and amortization. This method resulted in recognition of the obligation over the life of the property on a unit-of-production basis, with the estimated obligation netted in property cost as part of the accumulated depreciation, depletion and amortization balance. See Note 5.

Intangible Assets

An issue within the oil and gas industry has recently arisen regarding whether SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets,* require costs associated with mineral rights be accounted for and separately reported on the balance sheet as intangible assets. As is the common practice in the oil and gas industry, we include leasehold acquisition costs as a component of both producing properties and undeveloped properties on our consolidated balance sheets. This question of SFAS No. 141 and SFAS No. 142 applicability has been referred to the Financial Accounting Standards Board. If it is ultimately determined that SFAS No. 141 and SFAS No. 142 require intangible asset accounting treatment for costs associated with mineral rights, the following amounts would be reclassified on the consolidated balance sheets from producing properties, undeveloped properties and accumulated depreciation, depletion and amortization:

(in thousands)	December 31	
	2003	2002
Intangible Assets:		
Producing property leasehold acquisition costs	$2,093,318	$1,542,343
Undeveloped property leasehold acquisition costs	12,627	12,163
Total leasehold acquisition costs	2,105,945	1,554,506
Accumulated depletion	(438,151)	(336,374)
Net leasehold acquisition costs	$1,667,794	$1,218,132

Accounting for the costs of mineral rights as intangible assets under SFAS No. 141 and SFAS No. 142 would also require additional financial statement disclosures, but would not affect our method of amortization or assessment of impairment. Therefore, any resulting accounting change would have no effect on our consolidated income statements or statements of cash flows.

Royalty Trusts

We created Cross Timbers Royalty Trust in February 1991 and Hugoton Royalty Trust in December 1998 by conveying defined net profits interests in certain of our properties. Units of both trusts are traded on the New York Stock Exchange. We make monthly net profits payments to each trust based on revenues and costs from the related underlying properties. We own 54.3% of Hugoton Royalty Trust, which is the portion we retained following our sale of units in 1999 and 2000. The cost of our interest in Hugoton Royalty Trust is included in producing properties. We owned 22.7% of Cross Timbers Royalty Trust as a result of units we purchased on the open market from 1996 through 1998. In August 2003, our Board of Directors declared a dividend of 0.0059 units of Cross Timbers Royalty Trust units for each share of our common stock outstanding on September 2, 2003 (Note 14). Our Cross Timbers Royalty Trust units were distributed to our common stockholders on September 18, 2003, after which we no longer own any Cross Timbers Royalty Trust units. Amounts due the trusts, net of amounts retained by our ownership of Hugoton Royalty Trust units, are deducted from our revenues, taxes, production expenses and development costs.

Cash and Cash Equivalents

Cash equivalents are considered to be all highly liquid investments having an original maturity of three months or less.

Income Taxes

We record deferred income tax assets and liabilities to recognize timing differences between recognition of income for financial statement and income tax reporting purposes. Deferred tax assets are calculated using enacted tax rates applicable to taxable income in the years when we anticipate these timing differences will reverse. The effect of changes in tax rates is recognized in the period of enactment.

Other Assets

Other assets primarily include deferred debt costs that are amortized to interest expense over the term of the related debt (Note 3) and the long-term portion of gas balancing receivable (see "Revenue Recognition" below). Other than potential treatment of leasehold acquisition costs as intangible assets (see "Intangible Assets" above), we do not have any goodwill or significant intangible assets that are subject to potential impairment assessment. Other assets are presented net of accumulated amortization of $19. 8 million at December 31, 2003 and $18.3 million at December 31, 2002.

Derivatives

We use derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. On January 1, 2001, we adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended by SFAS Nos. 137, 138 and 149 (Note 7). SFAS No. 133 requires that all derivatives be recorded on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The fair value of call options and collars are generally determined under the Black-Scholes option-pricing model. Most values are confirmed by counterparties to the derivative.

Realized and unrealized gains and losses on derivatives that are not designated as hedges, as well as on the ineffective portion of hedge derivatives, are recorded as a derivative fair value gain or loss in the income statement. Unrealized gains and losses on effective cash flow hedge derivatives, as well as any deferred gain or loss realized upon early termination of effective hedge derivatives, are recorded as a component of accumulated other comprehensive income. When the hedged transaction occurs, the realized gain or loss, as well as any deferred gain or loss, on the hedge derivative is transferred from accumulated other comprehensive income to earnings. Gains and losses on commodity hedge derivatives are recognized in oil and gas revenues, and gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

To summarize, we record our derivatives at fair value in our consolidated balance sheets. Gains and losses resulting from changes in fair value and upon settlement are recorded as follows:

Derivative Type	Fair Value Gains/ Losses	Financial Statement Classification
Non-hedge derivatives and Hedge derivatives – ineffective portion	Unrealized and Realized	Derivative fair value (gain) loss in the Consolidated Income Statements
Hedge derivatives – effective portion	Unrealized	Accumulated other comprehensive income in Stockholders' Equity on the Consolidated Balance Sheets
	Realized	Hedged item as classified in the Consolidated Income Statements (e.g., gas revenue, oil revenue or interest expense)

To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective or the designated hedged transaction is not likely to occur, any unrealized gains or losses on the derivative are recognized immediately in the income statement as a derivative fair value gain or loss.

In conjunction with our hedging activities, we occasionally sell natural gas call options. Because sold options do not provide protection against declining prices, they do not qualify for hedge or loss deferral accounting. The opportunity loss, related to gas prices exceeding the fixed gas prices effectively provided by selling the call options, is recognized as a derivative fair value loss, rather than deferring the loss and recognizing it as reduced gas revenue when the hedged production occurs, as prescribed by hedge accounting.

Physical delivery contracts which are not expected to be net cash settled are deemed to be normal sales and therefore are not accounted for as derivatives. However, physical delivery contracts that have a price not clearly and closely associated with the asset sold are not a normal sale and must be accounted for as a non-hedge derivative (Note 8).

Revenue Recognition and Gas Balancing

Oil, gas and natural gas liquids revenues are recognized when the products are sold and delivery to the purchaser has occurred. At times we may sell more or less than our entitled share of gas production. When this happens, we use the entitlement method of accounting for gas sales, based on our net revenue interest in production. Accordingly, revenue is deferred for gas deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. The consolidated balance sheets include the following amounts related to production imbalances:

	December 31			
(in thousands)	2003		2002	
	Amount	Mcf	Amount	Mcf
Accounts receivable - current underproduction	$ 23,949	7,135	$ 17,248	6,178
Accounts payable - current overproduction	(19,366)	(5,900)	(14,381)	(5,165)
Net current gas underproduction balancing receivable	$ 4,583	1,235	$ 2,867	1,013
Other assets - noncurrent underproduction	$ 19,385	6,148	$ 14,934	5,642
Other long-term liabilities - noncurrent overproduction	(29,776)	(9,353)	(23,027)	(8,492)
Net long-term gas overproduction balancing payable	(10,391)	(3,205)	(8,093)	(2,850)
Other assets - carbon dioxide underproduction	1,977	12,354	1,868	11,675
Net long-term overproduction balancing payable	$ (8,414)		$ (6,225)	

Gas Gathering, Processing and Marketing Revenues

We market our gas, as well as some gas produced by third parties, to brokers, local distribution companies and end-users. Gas gathering and marketing revenues are recognized in the month of delivery based on customer nominations. Gas processing and marketing revenues are recorded net of cost of gas sold of $66. 3 million for 2003, $55.6 million for 2002 and $108.6 million for 2001. These amounts are net of intercompany eliminations.

Other Revenues

Other revenues include various gains and losses, including from lawsuits and other disputes, as well as from other than significant sales of property and equipment.

Loss Contingencies

We account for loss contingencies in accordance with SFAS No. 5, *Accounting for Contingencies*. Accordingly, when management determines that it is probable that an asset has been impaired or a liability has been incurred, we accrue our best estimate of the loss if it can be reasonably estimated. Our legal costs related to litigation are expensed as incurred. See Note 6.

Interest

Interest expense includes amortization of deferred debt costs and is presented net of interest income of $553,000 in 2003, $836,000 in 2002 and $716,000 in 2001, and net of capitalized interest of $2.2 million in 2003, $4.3 million in 2002 and $6.6 million in 2001. Interest is capitalized as producing property cost based on the weighted average interest rate and the cost of wells in process of drilling.

Stock-Based Compensation

In accordance with Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, no compensation is recorded for stock options or other stock-based awards that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. Compensation related to performance share grants with time vesting conditions is based on the fair value of the award at the grant date and recognized over the vesting period. Compensation related to performance shares with price target vesting is recognized when the price target is reached. See Note 12.

As required to be disclosed pursuant to SFAS No. 148, *Accounting for Stock-Based Compensation–Transition and Disclosure*, the following is the pro forma effect of recording stock-based compensation at the estimated fair value of awards on the grant date, as prescribed by SFAS No. 123, *Accounting for*

Stock-Based Compensation:

(in thousands, except per share data)	Year Ended December 31 2003	2002	2001
Net income as reported	$ 288,279	$ 186,059	$ 248,816
Add stock-based compensation expense included in the income statement, net of related tax effects	34,530	17,543	5,674
Deduct stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(33,498)	(19,762)	(49,947)
Pro forma net income	$ 289,311	$ 183,840	$ 204,543
Earnings per share:			
Basic - as reported	$ 1.28	$ 0.89	$ 1.22
Basic - pro forma	$ 1.29	$ 0.88	$ 1.00
Diluted - as reported	$ 1.27	$ 0.88	$ 1.20
Diluted - pro forma	$ 1.27	$ 0.87	$ 0.98

Earnings per Common Share

In accordance with SFAS No. 128, *Earnings Per Share*, we report basic earnings per share, which excludes the effect of potentially dilutive securities, and diluted earnings per share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. Unvested performance stock awards are included in the basic earnings per share calculation. See Note 10.

Segment Reporting

In accordance with SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we evaluated how the Company is organized and managed, and have identified only one operating segment, which is the exploration and production of oil, natural gas and natural gas liquids. We consider our gathering, processing and marketing functions as ancillary to our oil and gas producing activities. All of our assets are located in the United States, and all revenues are attributable to United States customers.

Our production is sold to various purchasers, based on their credit rating and location of our production. For the year ended December 31, 2003, sales to each of three purchasers were approximately 25%, 15% and 12% of total revenues. For the year ended December 31, 2002, sales to each of two purchasers were approximately 10% of total revenues. For the year ended December 31, 2001, sales to each of three purchasers were approximately 13%, 12% and 10% of total revenues. We believe that alternative purchasers are available, if necessary, to purchase production at prices substantially similar to those received from these significant purchasers. Because of declining credit ratings of some of our customers, we have greater concentrations of credit with a few large integrated energy companies with investment-grade ratings.

New Accounting Pronouncements

In May 2003, the Financial Accounting Standards Board issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity,* which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. Such financial instruments include mandatorily redeemable shares of stock, obligations to repurchase the issuer's equity shares and obligations that an issuer may settle by issuing a variable number of its equity shares. The Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. In November 2003, the effective date for SFAS No. 150 was deferred for provisions relating to certain financial instruments issued by consolidated subsidiaries. None of our consolidated entities currently have any of these financial instruments, and we do not anticipate SFAS No. 150 will have a material effect on future financial position or earnings.

In December 2003, the Financial Accounting Standards Board issued a revision of Interpretation No. 46 to clarify consolidation requirements for variable interest entities. We do not anticipate this interpretation to have an effect on our financial statements since we do not have interests in variable interest entities.

Also in December 2003, the Financial Accounting Standards Board revised SFAS No. 132, revising disclosures required about pensions and other post-retirement benefits. These revised disclosures are included in Note 12 for our post-retirement health plan. In accordance with a deferred effective date, future annual reporting will disclose future plan benefit payments expected to be paid for each of the five years following the latest balance sheet date and in the aggregate for the following five years.

In January 2004, the Financial Accounting Standards Board issued Staff Position No. 106-1 regarding treatment in post-retirement health plan accounting and disclosures for the effects of the Medicare Prescription Drug, Improvement and Modernization Act, which was signed by the President into law in December 2003. Because our post-retirement health plan does not provide prescription drug coverage beyond the date of eligibility for Medicare coverage, this change in Medicare coverage does not impact estimates for our benefit costs.

2. Related Party Transactions

Loans to Officers

In 1998 and 1999, five officers were loaned a total of $7.3 million to provide margin support for broker accounts where the officers held Company common stock. The loans were full recourse and due in December 2003, with an interest rate equal to our bank debt rate. In 2001, the officers fully repaid the loans and accrued interest. A portion of the repayment was funded by our market price purchase of 503,000 shares of our common stock from the officers for $6.5 million.

Other Transactions

In February 2004, our Board of Directors approved an agreement with a firm, partially owned by one of our directors, to establish fees that will be paid in connection with any advisory services the firm provides for up to $800 million in future acquisitions. The agreement is effective as of November 2003. For the first acquisition, we will pay a fee of $250,000 plus a transaction fee equal to 0.75% of the purchase price. For any subsequent acquisition closing, we will pay only the transaction fee. The initial term of the agreement expires December 31, 2004. To date, we have not paid the director-related company any amounts under this agreement. This director-related company represented the seller of properties for acquisitions totaling approximately $186 million that we closed in January 2004.

In connection with our sale of properties in 1999, the same director-related Company represented the purchaser and also invested in the purchase. We invested $584,000 in a limited partnership which had a small interest in these properties. Based on an impairment evaluation in 2003, we have written down this investment to $100,000.

The same director-related company performed consulting services in connection with our acquisition of properties in East Texas, Louisiana and the San Juan Basin of New Mexico during 2002 (Note 13). The director-related company received a fee of $2.4 million for these services, which was 1% of the total of the property purchase price and the related exchange transaction value.

The same director-related company performed consulting services in connection with a 1998 acquisition and was entitled to receive, at its election, either a 20% working interest or a 1% overriding royalty interest conveyed from our 100% working interest in the properties after payout of acquisition and operating costs. The Board of Directors authorized the purchase of this potential interest from the director-related company and other parties in November 2001 for $15 million, as supported by a third-party fairness opinion. The director-related company received $10 million of the total purchase price.

3. Debt

Our long-term debt consists of the following:

(in thousands)	December 31	
	2003	2002
Senior debt-		
Bank debt under revolving credit agreements due May 12, 2005 *(a)*, 2.54% at December 31, 2003	$ 502,000	$ 605,000
7½% senior notes due April 15, 2012	350,000	350,000
6¼% senior notes due April 15, 2013	400,000	-
Subordinated debt-		
8¾% senior subordinated notes due November 1, 2009	-	163,170
Total long-term debt	$1,252,000	$1,118,170

(a) In February 2004, we extended the maturity of bank debt upon entering a new revolving credit agreement that is due in February 2009.

Senior Debt

In May 2000, we entered a revolving credit agreement with commercial banks with a commitment of $800 million. Borrowings at December 31, 2003 under the loan agreement were $502 million with unused borrowing capacity of $298 million. Borrowings under the loan agreement at December 31, 2003 were based on London Interbank Offered Rates ("LIBOR") with maturity of one to six months and accrued at the applicable LIBOR rate plus 1.375%. The weighted average interest rate on bank debt was 2.6% during 2003, 3.2% during 2002 and 5.7% during 2001.

In February 2004, we fully repaid our revolving facility and entered a new five-year revolving credit agreement with commercial banks that matures in February 2009. The new agreement provides for an initial commitment amount of $800 million, which may be increased to a maximum of $1 billion, and an interest rate based on LIBOR plus 1%. The loan agreement provides the option of borrowing at floating interest rates based on the prime rate or at fixed rates for periods of up to six months based on certificate of deposit rates or LIBOR. Interest is paid at maturity, or quarterly if the term is for a period of 90 days or more. We also incur a commitment fee on unused borrowing commitments, which was 0.20% at February 2004. The agreement requires us to maintain a ratio of debt-to-total capitalization of not more than 60%. Borrowings under the loan agreement may be prepaid at any time without penalty. Our borrowings under the loan agreement were $169 million at February 27, 2004, with an interest rate of 2.16% and unused borrowing capacity of $631 million.

In April 2002, we sold $350 million of 7½% senior notes due in April 2012, with interest payable each April 15 and October 15. Net proceeds of $341.6 million from the sale of notes were used to finance property transactions (Note 13), to redeem our 9¼% senior subordinated notes and to reduce bank debt.

In April 2003, we sold $400 million of 6¼% senior notes due in April 2013 pursuant to Rule 144A under the Securities Act of 1933, which allows unregistered transactions with qualified institutional buyers. The notes were effectively registered with the Securities and Exchange Commission in June 2003. Interest is payable each April 15 and October 15. Net proceeds of $393.4 million from the sale of notes, combined with proceeds from the concurrent sale of common stock (Note 9), were used to finance our producing property acquisition from units of Williams of Tulsa, Oklahoma (Note 13), to redeem our 8¾% senior subordinated notes and to reduce bank debt.

In January 2004, we sold $500 million of 4.9% senior notes that were issued at 99.34% of par to yield 4.98% to maturity. Net proceeds of approximately $490 million were used to fund our January 2004 property acquisitions of $243 million (Note 13) and to reduce bank debt. The notes mature on February 1, 2014 and interest is payable each February 1 and August 1 beginning August 1, 2004.

The senior notes require no sinking fund. We may redeem all or a part of the senior notes at any time at a price of 100% of their principal balance plus accrued interest and a make-whole premium payment. The make-whole premium is calculated as any excess over the principal balance of the present value of remaining principal and interest payments at the U.S. Treasury rate for a comparable maturity plus no more than ½%. All of our senior notes are general unsecured senior indebtedness ranking equal to our other senior unsecured notes and above any senior subordinated notes.

Subordinated Debt

In April 1997, we sold $125 million of 9¼% senior subordinated notes due April 2007, and in October 1997, we sold $175 million of 8¾% senior subordinated notes due November 2009. Under the terms of an agreement with a bank counterparty, we purchased and canceled $9.7 million of 9¼% senior subordinated notes in April 2002, and we purchased and canceled $11.8 million of 8¾% senior subordinated notes in November 2002. In June 2002, we redeemed the remaining $115.3 million 9¼% notes at a redemption price of 104.625%, or $120.6 million, plus accrued interest of $1.8 million. In May 2003, we redeemed the remaining $163.2 million of our 8¾% senior subordinated notes at a redemption price of 104.375%, or $170.3 million, plus accrued interest of approximately $700,000. As a result of these transactions, we recorded a loss on extinguishment of debt of $8.5 million in 2002 and $9.6 million in 2003.

4. Income Tax

Our effective income tax rate was different than the statutory federal income tax rate for the following reasons:

(in thousands)	2003	2002	2001
Income tax expense at the federal statutory rate (35%)	$ 155,579	$ 100,362	$ 159,375
State and local income taxes and other	2,430	328	2,577
Income tax expense	$ 158,009	$ 100,690	$ 161,952

Components of income tax expense are as follows:

(in thousands)	2003	2002	2001
Current income tax	$ 294	$ 322	$ 847
Deferred income tax expense	148,304	121,396	159,257
Net operating loss carryforwards (added) used	9,411	(21,028)	1,848
Income tax expense	$ 158,009	$ 100,690	$ 161,952

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities. Our net deferred tax assets and liabilities are recorded as a current asset of $32.5 million and a long-term liability of $426.7 million at December 31, 2003 and as a current asset of $32.7 million and a long-term liability of $286.5 million at December 31, 2002. Significant components of net deferred tax assets and liabilities are:

(in thousands)	December 31	
	2003	2002
Deferred tax assets:		
Net operating loss carryforwards	$ 84,001	$ 88,549
Derivative fair value loss	40,144	52,834
Other	6,720	7,981
Total deferred tax assets	130,865	149,364
Deferred tax liabilities:		
Property and equipment	507,447	374,614
Derivative fair value gain	4,199	14,581
Other	13,494	13,961
Total deferred tax liabilities	525,140	403,156
Net deferred tax liabilities	$ (394,275)	$ (253,792)

As of December 31, 2003, we had estimated tax loss carryforwards of approximately $242 million, of which $1 million are related to capital losses. The capital loss carryforwards expire in 2004, while the remaining ordinary loss carryforwards are scheduled to expire in 2010 through 2023. Approximately $22 million of the tax loss carryforwards are the result of acquisitions. We have not booked any valuation allowance because we believe we have tax planning strategies available to realize our tax loss carryforwards.

5. Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties (including removal of our offshore platforms in Alaska) at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. As of the January 1, 2003 adoption date of SFAS 143, we recorded a long-term liability for asset retirement obligation of $75.3 million, an increase in property cost of $60.7 million, a reduction of accumulated depreciation, depletion and amortization of $17.3 million and a cumulative effect of accounting change gain, net of tax, of $1.8 million. The following is a reconciliation of the asset retirement obligation for the year ended December 31, 2003:

(in thousands)	
Asset retirement obligation, January 1	$ 75,256
Liability incurred upon acquiring and drilling wells	13,879
Liability settled upon plugging and abandoning wells	(1,086)
Accretion of discount expense	5,330
Asset retirement obligation, December 31	$ 93,379

Based on the same assumptions used in the calculation of our asset retirement obligation at January 1, 2003, we estimate that this obligation would have been $62.2 million at January 1, 2002 and $54.7 million at January 1, 2001, if we had adopted SFAS No. 143 as of those dates. The estimated pro forma effect of earlier adoption on 2002 and 2001 net income and earnings per share is not material.

We have not estimated the fair value of assets legally restricted for purposes of settling asset retirement obligations because such determination involves complex assumptions and considerable analysis. See Note 16 for information reporting the standardized measure of future net cash flows from proved reserves, using assumptions required by the Financial Accounting Standards Board.

6. Commitments and Contingencies

Leases

We lease compressors, offices, vehicles, aircraft and certain other equipment in our primary locations under noncancelable operating leases. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2003, minimum future lease payments for all noncancelable lease agreements (including the sale and operating leaseback agreements described below) were as follows:

(in thousands)	
2004	$ 23,343
2005	20,522
2006	15,712
2007	14,788
2008	14,248
Remaining	38,306
Total	$ 126,919

Amounts incurred under operating leases (including renewable monthly leases) were $31.7 million in 2003, $26.6 million in 2002 and $20.6 million in 2001.

In March 1996, we sold our Tyrone gas processing plant and related gathering system for $28 million and entered an agreement to lease the facility from the buyers for an initial term of eight years at annual rentals of $4 million with fixed renewal options for an additional 13 years at a total cost of $7.8 million. This transaction was recorded as a sale and operating leaseback, with no gain or loss on the sale. In March 2004, we extended the lease until March 2006.

In November 1996, we sold a gathering system in Major County, Oklahoma for $8 million and entered an agreement to lease the facility from the buyers for an initial term of eight years, with fixed renewal options for an additional ten years. Rentals are adjusted monthly based on the 30-day LIBOR rate and may be irrevocably fixed by us with 20 days advance notice. As of December 31, 2003, annual rentals were $1.4 million. This transaction was recorded as a sale and operating leaseback, with a deferred gain of $3.4 million on the sale. The deferred gain is amortized over the lease term based on pro rata rentals and is recorded in other long-term liabilities in the accompanying consolidated balance sheets. The deferred gain balance at December 31, 2003 was $1 million.

Under each of the above sale and leaseback transactions, we do not have the right or option to purchase, nor does the lessor have the obligation to sell, the facility at any time. However, if the lessor decides to sell the facility at the end of the initial term or any renewal period, the lessor must first offer to sell it to us at its fair market value. Additionally, we have the right of first refusal of any third party offers to buy the facility after the initial term.

Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts we are obligated to transport minimum daily gas volumes or pay for any deficiencies at a specified reservation fee rate. As calculated on a monthly basis, our failure to deliver these minimum volumes to the pipeline, requires us to pay the pipeline for any deficiency. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under our firm transportation contracts, therefore avoiding payment for deficiencies. As of December 31, 2003, maximum commitments under our transportation contracts were as follows:

(in thousands)	
2004	$ 12,982
2005	19,928
2006	20,490
2007	19,591
2008	18,804
Remaining	54,398
	$ 146,193

Guarantees

Under the terms of some of our operating leases for compressors, airplanes and vehicles, we have various residual value guarantees and other payment provisions upon our election to return the equipment under certain specified conditions. As of December 31, 2003, we estimate the total contingent payable under these guarantees does not exceed $5 million. Guarantees related to leases entered during 2003 were not material.

Employment Agreements

Two executive officers have year-to-year employment agreements with us. The agreements are automatically renewed each year-end unless terminated by either party upon thirty days notice prior to each December 31. Under these agreements, the officers receive a minimum annual salary of $625,000 and $450,000, respectively, and are entitled to participate in any incentive compensation programs administered by the Board of Directors. The agreements also provide that, in the event the officer terminates his employment for good reason, as defined in the agreement, we terminate the employee without cause or a change in control of the Company occurs, the officer is entitled to a lump-sum payment of three times the officer's most recent annual compensation, including any special bonuses or other compensation required to be designated as a bonus under the rules and regulations of the Securities and Exchange Commission. In addition, the officer is entitled to receive a payment sufficient to make the officer whole for any excise tax on excess parachute payments imposed by the Internal Revenue Code.

Commodity Commitments

We have entered into futures contracts, collars and swap agreements that effectively fix gas prices. See Note 8.

Drilling Contracts

We have agreements to use 22 drilling rigs in 2004 with total commitments of $45.2 million. Early termination of these contracts would require fees totaling $4.4 million in lieu of these commitments.

Litigation

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the U. S. District Court for the Western District of Oklahoma against us and certain of our subsidiaries by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the False Claims Act. The plaintiff alleges that we underpaid royalties on gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% during at least the past 10 years as a result of mismeasuring the volume of gas and incorrectly analyzing its heating content. The plaintiff also alleges that we have failed to pay the fair market value of the carbon dioxide produced. The plaintiff seeks to recover the amount of royalties not paid, together with treble damages, a civil penalty of $5,000 to $10,000 for each violation and attorney fees and expenses. The plaintiff also seeks an order for us to cease the allegedly improper measuring practices. After its review, the Department of Justice decided in April 1999 not to intervene and asked the court to unseal the case. The court unsealed the case in May 1999. A multi-district litigation panel ordered that the lawsuits against us and other companies filed by Grynberg be transferred and consolidated to the federal district court in Wyoming. We believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

In June 2001, we were served with a lawsuit styled *Price, et al. v. Gas Pipelines, et al.* (formerly *Quinque* case). The action was filed in the District Court of Stevens County, Kansas, against us and one of our subsidiaries, along with over 200 natural gas transmission companies, producers, gatherers and processors of natural gas. Plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas working interest owners, overriding royalty owners and royalty owners either from whom the defendants had purchased natural gas or who received economic benefit from the sale of such gas since January 1, 1974. The allegations in the case are similar to those in the *Grynberg* case; however, the *Price* case broadens the claims to cover all oil and gas leases (other than the Federal and Native American leases that are the subject of the *Grynberg* case). The complaint alleges that the defendants have mismeasured both the volume and heating content of natural gas delivered into their pipelines resulting in underpayments to the plaintiffs. Plaintiffs assert a breach of contract claim, negligent or intentional misrepresentation, civil conspiracy, common carrier liability, conversion, violation of a variety of Kansas statutes and other common law causes of action. The amount of damages was not specified in the complaint. In February 2002, we, along with one of our subsidiaries, were dismissed from the suit and another subsidiary of the Company was added. A hearing was held in January 2003, and the court held that a class should not be certified. Plaintiffs' counsel has filed an amended class action petition, which reduces the proposed class to only royalty owners, reduces the claims to mismeasurement of volume only, conspiracy, unjust enrichment and accounting, and only applies as to gas measured in Kansas, Colorado and Wyoming. We believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

On August 5, 2003, the *Price* plaintiffs served one of our subsidiaries with a new original class action petition styled *Price, et al. v. Gas Pipelines, et al*. The action was filed in the District Court of Stevens County, Kansas, against natural gas pipeline owners and operators. Plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The new petition alleges the same improper analysis of gas heating content, which had previously been alleged in the *Price* case discussed above until it was removed from the case by the filing of the amended class action petition. In all other respects, the new petition appears to be identical to the amended class action petition in that it has a proposed class of only royalty owners, alleges conspiracy, unjust enrichment and accounting, and only applies as to gas measured in Kansas, Colorado and Wyoming. The amount of damages was not specified in the complaint. We believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

On April 3, 1998, a class action lawsuit, styled *Booth, et al. v. Cross Timbers Oil Company*, was filed against us in the District Court of Dewey County, Oklahoma. The action was filed on behalf of all persons who, at any time since June 1991, have been paid royalties on gas produced from any gas well within the State of Oklahoma under which we have assumed the obligation to pay royalties. The plaintiffs alleged that we reduced royalty payments by post-production deductions and entered into contracts with subsidiaries that were not arm's-length transactions. The plaintiffs further alleged that these actions reduced the royalties paid to the plaintiffs and those similarly situated, and that such actions were a breach of the leases under which the royalties are paid. In July 2003, we paid $2.5 million to settle the plaintiffs' claims for the period January 1, 1993 through June 30, 2002. Our portion of this liability, net of amounts allocable to Hugoton Royalty Trust units we do not own, was $2.1 million, which had been accrued in our financial statements.

In February 2000, the Department of Interior notified us and several other producers that certain Native American leases located in the San Juan Basin had expired because of the failure of the leases to produce in paying quantities from February through August 1990. The Department of Interior demanded abandonment of the property as well as payment of the gross proceeds from the wells minus royalties paid from the date of the alleged cessation of production to present. In January 2004, the Department of Interior withdrew its claim against us.

We are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management and legal counsel do not believe that the ultimate resolution of these claims, including the lawsuits described above, will have a material effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year.

Other

To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

7. Financial Instruments

We use financial and commodity-based derivative contracts to manage exposures to commodity price and interest rate fluctuations. We do not hold or issue derivative financial instruments for speculative or trading purposes.

On January 1, 2001, we adopted SFAS No. 133, as amended by SFAS Nos. 137, 138 and 149, by recording a one-time after-tax charge of $44.6 million in the income statement for the cumulative effect of a change in accounting principle and an unrealized loss of $67.3 million in accumulated other comprehensive income. The unrealized loss was related to the derivative fair value of cash flow hedges. The charge to the income statement was primarily related to our physical delivery contract with crude oil-based pricing, also referred to as the Enron Btu swap contract.

We often enter gas physical delivery contracts to effectively provide gas price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the financial statements.

In accordance with SFAS No. 133, all derivatives are recorded on the balance sheet at estimated fair market value.

Btu Swap Contracts

In 1995, we entered a contract to sell gas based on crude oil pricing, also referred to as the Enron Btu swap contract. This contract was terminated as a result of the Enron bankruptcy. Because the contract pricing was not clearly and closely associated with natural gas prices, it was considered a non-hedge derivative financial instrument under SFAS No. 133 beginning January 1, 2001, with changes in fair value recorded as a derivative (gain) loss in the income statement.

Prior to termination of the Enron Btu swap contract, we entered Btu swap contracts with another counterparty to effectively defer until 2005 and 2006 any cash flow impact related to 25,000 Mcf of daily gas deliveries in 2002 that were to be made under the Enron Btu swap contract. Changes in fair value of these contracts are recorded as a derivative (gain) loss in the income statement. In March 2002, we terminated some of these contracts with maturities of May through December 2002 and received $6.6 million from the counterparty. Because these Btu swap contracts are non-hedge derivatives, most of the related $6.6 million gain related to their termination had previously been recorded in 2001 derivative fair value gain.

Commodity Price Hedging Instruments

We periodically enter into futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on crude oil and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts, we pay this excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We have hedged a portion of our exposure to variability in future cash flows from natural gas sales through December 2005. See Note 8.

Interest Rate Swap Agreements

In September 1998, to reduce variable interest rate exposure on debt, we entered into a series of interest rate swap agreements, effectively fixing our interest rate at an average of 6.9% on a total notional balance of $150 million until September 2005. In 1999 and 2000, we terminated these interest rate swaps, resulting in a gain of $2 million. This gain has been deferred and is being amortized against interest expense through September 2005.

Derivative Fair Value (Gain) Loss

The components of derivative fair value (gain) loss, as reflected in the consolidated income statements are:

(in thousands)

	2003	2002	2001
Change in fair value of Btu swap contracts	$ 5,115	$ 1,046	$ (23,428)
Change in fair value of other derivatives that do not qualify for hedge accounting	(2,187)	(6,505)	(31,099)
Ineffective portion of derivatives qualifying for hedge accounting	7,273	2,860	157
Derivative fair value (gain) loss	$ 10,201	$ (2,599)	$ (54,370)

Fair Value of Financial Instruments

Because of their short-term maturity, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying values at December 31, 2003 and 2002. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2003		December 31, 2002	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivative Assets:				
Fixed-price natural gas futures and swaps	$ 11,997	$ 11,997	$ 41,483	$ 41,483
Fixed-price crude futures and differential	-	-	177	177
Derivative Liabilities:				
Fixed-price natural gas futures and swaps	(96,702)	(96,702)	(135,188)	(135,188)
Fixed-price crude futures and differential	-	-	(2,886)	(2,886)
Btu swap contracts	(17,995)	(17,995)	(12,880)	(12,880)
Net derivative asset (liability)	$ (102,700)	$ (102,700)	$ (109,294)	$ (109,294)
Long-term debt	$(1,252,000)	$(1,275,285)	$(1,118,170)	$(1,146,572)

The fair value of bank borrowings approximates their carrying value because of short-term interest rate maturities. The fair value of senior notes and subordinated long-term debt is based on current market quotes. The fair value of futures contracts and swap agreements is estimated based on the exchange-trade value of NYMEX contracts and market commodity prices for the applicable future periods.

Changes in fair value of derivative assets and liabilities are the result of changes in oil and gas prices and interest rates. Futures and swaps are generally designated as hedges of commodity price risks, and accordingly, changes in their values are predominantly recorded in accumulated other comprehensive income until the hedged transaction occurs. We do not hold derivatives for trading or speculative purposes.

Concentrations of Credit Risk

Although our cash equivalents and derivative financial instruments are exposed to the risk of credit loss, we do not believe such risk to be significant. Cash equivalents are high-grade, short-term securities, placed with highly rated financial institutions. Most of our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. Because of declining credit ratings of some of our customers, we have greater concentrations of credit with a few large integrated energy companies with investment grade ratings. Financial and commodity-based swap contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions, and we have master netting agreements with most counterparties that provide for offsetting payables against receivables from separate swap contracts. Letters of credit or other appropriate security are obtained as considered necessary to limit risk of loss. We recorded an allowance for collectibility of all accounts receivable of $6.3 million at December 31, 2003 and $5.5 million at December 31, 2002. Our bad debt provision was $1.3 million in 2003, $980,000 in 2002 and $978,000 in 2001.

8. Commodity Sales Commitments

Our policy is to routinely hedge a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the benefit of rising prices, management plans to continue this strategy because of the benefits of more predictable production growth and cash flows. In addition to selling gas under fixed price physical delivery contracts, we enter futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on natural gas and crude oil sales. We have hedged a portion of our exposure to variability in future cash flows from natural gas sales through December 2005.

Natural Gas

We have entered into natural gas futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 7 regarding accounting for commodity hedges.

		Futures Contracts and Swap Agreements	
Production Period		Mcf per Day	Average NYMEX Price per Mcf
2004	March to June	380,000	$ 4.77
	July to December	400,000	4.77
2005	January to December	100,000	5.21

The price we receive for our gas production is generally less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors. We have entered basis swap agreements that effectively fix the basis adjustment for the following delivery locations and periods:

	Delivery Location					
Production Period	Arkoma	Houston Ship Channel	Mid-Continent	Rockies	San Juan Basin	Total
2004						
March						
Mcf per day	50,000	120,000	70,000	10,000	65,000	315,000
Basis per Mcf *(a)*	$ (0.11)	$ (0.04)	$ (0.24)	$ (0.56)	$ (0.57)	
April to June						
Mcf per day	70,000	210,000	60,000	10,000	55,000	405,000
Basis per Mcf *(a)*	$ (0.12)	$ (0.04)	$ (0.26)	$ (0.68)	$ (0.66)	
July						
Mcf per day	70,000	200,000	60,000	10,000	55,000	395,000
Basis per Mcf *(a)*	$ (0.12)	$ (0.04)	$ (0.26)	$ (0.68)	$ (0.66)	
August						
Mcf per day	70,000	180,000	60,000	10,000	55,000	375,000
Basis per Mcf *(a)*	$ (0.12)	$ (0.04)	$ (0.26)	$ (0.68)	$ (0.66)	
September to October						
Mcf per day	70,000	160,000	60,000	10,000	55,000	355,000
Basis per Mcf *(a)*	$ (0.12)	$ (0.04)	$ (0.26)	$ (0.68)	$ (0.66)	
November to December						
Mcf per day	60,000	30,000	60,000	5,000	55,000	210,000
Basis per Mcf *(a)*	$ (0.11)	$ (0.05)	$ (0.26)	$ (0.66)	$ (0.66)	
2005						
January to March						
Mcf per day	10,000	-	-	5,000	30,000	45,000
Basis per Mcf *(a)*	$ (0.05)	-	-	$ (0.66)	$ (0.66)	

(a) Reductions to NYMEX gas prices for delivery location.

Net gains and losses on futures, collars and basis swap hedge contracts decreased gas revenue by $193 million in 2003 and $11.1 million in 2001, and increased gas revenue by $57.4 million in 2002. Including the effect of fixed price physical delivery contracts, all hedging activities increased gas revenue by $95.4 million in 2002 and $97 million in 2001. There were no fixed price physical delivery contracts in 2003. As of December 31, 2003, an unrealized pre-tax derivative fair value loss of $81.9 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income. Based on December 31 mark-to-market prices, $81.4 million of this fair value loss is expected to be reclassified into earnings in 2004. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date.

The settlement of futures contracts and basis swap agreements related to January and February 2004 gas production resulted in reduced gas revenue of approximately $19.5 million, or $0.41 per Mcf.

Crude Oil

In 2003, net losses on oil futures hedge contracts decreased oil revenue by $3.9 million. During 2002, net losses on oil futures hedge contracts decreased oil revenue by $1.3 million, while changes in fair value of sour oil basis swap contracts resulted in a derivative fair value gain of $300,000. As of December 31, 2003, there were no outstanding oil futures, collars or basis swap contracts.

Physical Delivery Contracts

From August 1995 through July 1998 we received an additional $0.30 to $0.35 per Mcf on 10,000 Mcf of gas per day. In exchange therefor, we agreed to sell 34,344 Mcf per day at the index price in 2001 and 35,500 Mcf per day from 2002 through July 2005 at a price of approximately 10% of the average NYMEX futures price for intermediate crude oil. See Note 7 regarding accounting for this contract, also referred to as the Enron Btu swap contract, which was terminated as a result of the Enron bankruptcy, and regarding a related derivative commitment with another counterparty.

In addition to the Enron Btu swap contract, Enron Corporation was a purchaser of natural gas under other physical delivery contracts and was counterparty to some of our hedge derivative contracts at the time of its bankruptcy in December 2001. In settlement of all obligations, we paid Enron $6 million in December 2002. As a result of this settlement, in 2002 we recognized $14.1 million in previously unrecognized gas revenue related to physical delivery contracts and a gain of $2.1 million.

In 1998, we sold a production payment, payable from future production from certain properties acquired in an acquisition, to EEX Corporation for $30 million. Under the terms of the production payment conveyance and related delivery agreement, we committed to deliver to EEX a total of approximately 34.3 Bcf (27.8 Bcf net to our interest) of gas during the 10-year period beginning January 1, 2002, with scheduled deliveries by year, subject to certain variables. EEX will reimburse us for all royalty and production and property tax payments related to such deliveries. EEX will also pay us an operating fee of $0.257 per Mcf for deliveries, which fee will be escalated annually at a rate of 5.5%. In 2001 and 2002, we repurchased 18.3 Bcf (14.8 Bcf net) of gas under the production payment for $20.7 million. We expect to begin delivery of the remaining 16.0 Bcf (13.0 Bcf net) of gas in 2006.

9. Equity

Stock Splits

We effected a three-for-two common stock split on June 5, 2001, a four-for-three stock split on March 18, 2003 and will effect a five-for-four stock split on March 17, 2004. All common stock shares, treasury stock shares and per share amounts have been retroactively restated to reflect these stock splits.

Common Stock

The following reflects our common stock activity:

(in thousands)	Shares Issued 2003	Shares Issued 2002	Shares Issued 2001	Shares in Treasury 2003	Shares in Treasury 2002	Shares in Treasury 2001
Balance, January 1	226,225	219,981	206,466	14,597	13,694	12,579
Issuance/vesting of performance shares	3,332	1,668	1,110	1,188	784	361
Stock option and warrant exercises	3,342	4,576	3,590	-	3	39
Treasury stock purchases	-	-	-	113	116	715
Common stock offering	17,250	-	-	-	-	-
Preferred stock converted to common	-	-	8,815	-	-	-
Cancellation of shares	(15,898)	-	-	(15,898)	-	-
Balance, December 31	234,251	226,225	219,981	-	14,597	13,694

In April 2003, we completed a public offering of 17.3 million shares of common stock at $15.00 per share. Net proceeds from the offering of $248 million and net proceeds from the concurrent sale of senior notes (Note 3) were used to fund our producing property acquisition from units of Williams of Tulsa, Oklahoma (Note 13), to redeem our 8¾% senior subordinated notes and to reduce bank debt.

Treasury Stock

In February 2004, the Board of Directors authorized the cancellation of treasury shares as of December 31, 2003. This retirement of treasury shares is reflected in the December 31, 2003 consolidated balance sheet, resulting in a reduction of treasury stock and additional paid-in-capital of $102 million, and a reduction in shares in treasury and shares issued of 15,898,000 shares.

As of March 15, 2004, 10.8 million shares remain under the May 2000 Board of Directors' authorization to repurchase 11.3 million shares of our common stock.

Stockholder Rights Plan

In August 1998, the Board of Directors adopted a stockholder rights plan that is designed to assure that all stockholders receive fair and equal treatment in the event of any proposed takeover of the Company. Under this plan, one preferred share purchase right is attached to each outstanding share of common stock. Each right entitles stockholders to buy one one-thousandth of a share of newly created Series A Junior Participating Preferred Stock at an exercise price of $80, subject to adjustment in the event a person acquires or makes a tender or exchange offer for 15% or more of the outstanding common stock. In such event, each right entitles the holder (other than the person acquiring 15% or more of the outstanding common stock) to purchase shares of common stock with a market value of twice the right's exercise price. At any time prior to such event, the Board of Directors may redeem the rights at one cent per right. The rights can be transferred only with common stock and expire in August 2008.

Shelf Registration Statement

In June 2003, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities, preferred stock, common stock, or warrants to purchase debt or stock. The total face amount of securities that can be offered is $1 billion, at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities will be used for general corporate purposes, including reduction of bank debt. In January 2004, we sold $500 million of 4.9% senior notes under the shelf registration statement. See Note 3.

Common Stock Warrants

As partial consideration for producing properties acquired in December 1997, we issued warrants to purchase 3.6 million shares of common stock at a price of $4.02 per share for a period of five years. These warrants, valued at $5.7 million when issued and recorded as additional paid-in capital, were exercised in August 2002, resulting in an increase to common stock and additional paid-in capital of $14.3 million.

Common Stock Dividends

The Board of Directors declared quarterly dividends of $0.004 per common share for first quarter 2001 and $0.006 per common share each quarter for the remainder of 2001 and 2002 and $0.008 per common share for each quarter in 2003. In February 2004, the Board of Directors declared a first quarter 2004 dividend of $0.01 per share. Because of the five-for-four stock split to be effected on March 17, 2004, this represents a 25% increase in the dividend rate.

Our ability to pay dividends is dependent upon available cash flow, as well as other factors. Although there is a cumulative maximum restriction on distributions to common stockholders under our 7½% senior note and 6¼% senior note covenants, because of retained and projected future earnings, we do not anticipate these restrictions will affect future dividends.

Series A Convertible Preferred Stock

During 2001, 1.1 million shares of convertible preferred stock were converted into 8.8 million shares of common stock.

See also Note 12.

10. Earnings Per Share

The following reconciles earnings (numerator) and shares (denominator) used in the computation of basic and diluted earnings per share:

(in thousands, except per share data)	Earnings	Shares	Earnings per Share
2003			
Basic	$ 288,279	224,749	$ 1.28
Effect of dilutive securities:			
Stock options	-	3,065	
Diluted	$ 288,279	227,814	$ 1.27
2002			
Basic	$ 186,059	208,375	$ 0.89
Effect of dilutive securities:			
Stock options	-	1,034	
Warrants	-	1,406	
Diluted	$ 186,059	210,815	$ 0.88
2001			
Basic	$ 248,816	204,176	$ 1.22
Effect of dilutive securities:			
Stock options	-	806	
Preferred stock	-	628	
Warrants	-	2,100	
Diluted	$ 248,816	207,710	$ 1.20

11. Supplemental Cash Flow Information

The consolidated statements of cash flows exclude the following non-cash transactions (Notes 9, 12 and 14):

- Distribution of 1,360,000 Cross Timbers Royalty Trust units as a dividend to common stockholders in 2003

- Conversion of 1.1 million shares of preferred stock to 8.8 million shares of common stock in 2001

- Performance shares activity, including:

  - Grants of 3.3 million shares in 2003, 1.8 million shares in 2002 and 1.5 million shares in 2001 to key employees and nonemployee directors

  - Vesting of 2.6 million in 2003, 2.1 million shares in 2002 and 1 million shares in 2001

  - Forfeiture of 15,000 shares in 2003 and 15,000 shares in 2001

Interest payments in 2003 totaled $60.9 million (including $2.2 million of capitalized interest), $52.1 million in 2002 (including $4.3 million of capitalized interest) and $59.6 million in 2001 (including $6.6 million of capitalized interest). Net income tax payments were $5.3 million during 2003 and $405,000 during 2002; income tax refunds were $140,000 in 2001.

Because we do not recognize compensation related to stock options granted, the tax benefit realized upon exercise of stock options is recorded as an increase in additional paid-in capital. This is a non-cash tax benefit which is part of our net operating loss carryforward, and accordingly, is not reflected in our consolidated statements of cash flows (Note 4). This tax benefit from exercise of stock options was $22.7 million in 2003, $1.8 million in 2002 and $14.1 million in 2001.

12. Employee Benefit Plans

401(k) Plan

We sponsor a 401(k) benefit plan that allows employees to contribute and defer a portion of their wages. We match employee contributions of up to 10% of wages, subject to annual dollar maximums established by the federal government. Employee contributions vest immediately while our matching contributions vest 100% upon completion of three years of service. All employees over 21 years of age may participate. Company contributions under the plan were $5.2 million in 2003, $4.5 million in 2002 and $3.9 million in 2001.

Post-Retirement Health Plan

Effective January 1, 2001, we adopted a medical plan for employees who retire at age 55 or over, as well as directors age 55 or over, with a minimum of five years service. During 2003, our retiree medical plan was amended to provide benefits to employees with any combination of age and qualified years of service that total 60, with a minimum age of 45 and a minimum of five years full-time service. Directors are eligible to receive benefits when their combined age and years of service on the Board totals 60, with a minimum age of 45 and a minimum of five years of service. Benefits under the plan are the same as for active employees, and continue until the retired employee or director or the employee's or director's dependents are eligible for Medicare or another similar federal health insurance program. Post-retirement medical benefits are not prefunded but are paid when incurred. The status of our post-retirement health plan for 2003, 2002 and 2001 is as follows:

(in thousands)	December 31 2003	2002	2001
Change in benefit obligation:			
Benefit obligation at January 1	$ 3,096	$ 1,078	$ 804
Service cost	729	477	221
Interest cost	275	185	62
Plan amendments	2,380	490	-
Actuarial (gain) loss	(3,273)	904	1
Benefit payments	(85)	(38)	(10)
Benefit obligation at December 31	$ 3,122	$ 3,096	$ 1,078
Amounts recognized in the consolidated balance sheet:			
Funded status	$ (3,122)	$ (3,096)	$ (1,078)
Unrecognized net actuarial (gain) loss	(3,391)	698	(9)
Unrecognized prior service cost	2,738	424	-
Accrued benefit liability, as recognized in the consolidated balance sheet at December 31	$ (3,775)	$ (1,974)	$ (1,087)
Components of net periodic benefit cost:			
Service cost	729	$ 477	$ 221
Interest cost	275	185	62
Amortization of prior service cost	66	66	804
Recognized net actuarial loss	731	159	-
Net periodic benefit cost	$ 1,801	$ 887	$ 1,087

Unrecognized net actuarial gain and prior service costs are amortized to expense over the lesser of the estimated average remaining service life of plan participants or seven years. Including such amortization, the 2004 accrued benefit cost is expected to be less than $1 million.

The following are assumptions used by us to determine our benefit obligation as of December 31 of each of the years presented:

	2003	2002	2001
Weighted average discount rate	6.5%	6.5%	7.5%
Health care cost trend rate assumed for the following year	9%	9%	9%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	6%	6%	6%
Year that the rate reaches the ultimate trend rate	2009	2008	2007

Assumed health care cost trends have a significant effect on the amounts reported for health care plans. A one percentage point change in assumed health care cost trend rates would have the following estimated effects as of December 31, 2003:

(in thousands)	One Percentage Point Increase	Decrease
Effect on total service and interest cost	$ 74	$ 63
Effect on the post-retirement benefit obligation	$ 370	$ 323

1998 Stock Incentive Plan

Under the 1998 Stock Incentive Plan, a total of 22.5 million shares of common stock may be issued pursuant to grants of stock options or performance shares. Grants under the 1998 Plan are subject to the provision that outstanding stock options and performance shares cannot exceed 6% of our outstanding common stock at the time such grants are made. Stock options generally vest and become exercisable annually in equal amounts over a five-year period, with provision for accelerated vesting when the common stock price reaches specified levels. There were 4 million options outstanding at December 31, 2003 that are exercisable, 14,000 options outstanding that vest when the common stock price reaches $23.86, 642,000 options outstanding that vest when the common stock price reaches $24.00, 642,000 options outstanding that vest when the common stock price reaches $26.00 and 642,000 options outstanding that vest when the common stock price reaches $28.00. At December 31, 2003, there were 256,000 shares available for grant under the 1998 Plan. General and administrative expense includes compensation related to stock options of $2.3 million in 2003 and $900,000 in 2001.

In February and March 2004, 14,000 options vested when the stock price reached $23.86, 642,000 options vested when the stock price reached $24.00 and 642,000 options vested when the stock price reached $26.00.

Performance Shares

Performance shares granted under the 1998 Plan are subject to restrictions determined by the Compensation Committee of the Board of Directors and are subject to forfeiture if performance targets are not met. Otherwise, holders of performance shares generally have all the voting, dividend and other rights of other common stockholders. We issued performance shares to key employees and nonemployee directors totaling 3.3 million in 2003, 1.8 million in 2002 and 1.5 million in 2001. The weighted average fair value of performance shares when granted was $19.61 per share in 2003, $12.98 per share in 2002 and $10.98 per share in 2001. Performance shares vested, totaling 2.6 million in 2003, 2.1 million in 2002 and 1 million in 2001, when the common stock price reached specified levels. In 2003 and 2001, 15,000 performance shares issued in each of those years were forfeited. General and administrative expense includes compensation related to performance shares of $50.8 million in 2003, $27 million in 2002 and $8.7 million in 2001. Treasury stock purchases related to vested performance shares totaled $22.7 million is 2003, $10.3 million in 2002 and $4.2 million in 2001.

At December 31, 2003, deferred compensation of $24.8 million was recorded as an offset to additional paid-in-capital for 1,096,000 performance shares outstanding. These performance shares vest when the common stock reaches the following prices:

Shares Outstanding at December 31, 2003	Vesting Price
250,000	$ 23.86
296,000	$ 24.00
275,000	$ 26.00
275,000	$ 28.00
1,096,000	

As of March 2, 2004, the common stock price reached a high of $26.00, resulting in vesting of 821,000 performance shares outstanding at year end 2003, as well as 500,000 additional shares that were granted in February and March 2004 with vesting at $24.86 and $25.86. Total non-cash incentive compensation related to 2004 vesting of performance shares through March 2 was $33.2 million. In March 2004, an additional 250,000 shares were granted that vest when the common stock price reaches $26.86.

As adjusted for stock splits, it has been the historical practice since 2001 for the Board of Directors to grant executive officers 250,000 performance shares with vesting that generally occurs at $1.00 increments in the common stock price. Before adjustment for stock splits, the grant to executive officers initially was for 100,000 performance shares with vesting and additional grants at $2.50 increments in the common stock price.

In 2001, the Board approved an agreement with certain executive officers under which the officers, immediately prior to a change in control of the Company, will receive a total grant of 250,000 performance shares for every $1.00 increment in the closing price of our common stock above $12.00. Unless otherwise designated by the Board, the number of performance shares granted under the agreement will be reduced by the number of performance shares awarded to the officers between the date of the agreement and the date of the change in control. Certain officers will also receive a total grant of 387,500 performance shares immediately prior to a change in control without regard to the price of our common stock.

Option Activity and Balances

The following summarizes option activity and balances from 2001 through 2003:

	Weighted Average Exercise Price	Stock Options
2001		
Beginning of year	$ 8.06	10,978,693
Grants	11.25	9,592,818
Exercises	7.91	(8,876,091)
Forfeitures	11.29	(135,000)
End of year	10.76	11,560,420
Exercisable at end of year	10.82	10,902,246
2002		
Beginning of year	$ 10.76	11,560,420
Grants	13.66	828,508
Exercises	8.69	(1,193,579)
Forfeitures	10.53	(54,798)
End of year	11.20	11,140,551
Exercisable at end of year	11.10	10,754,354
2003		
Beginning of year	$ 11.20	11,140,551
Grants	20.08	2,647,656
Exercises	11.27	(7,822,592)
Forfeitures	18.51	(41,250)
End of year	14.87	5,924,365
Exercisable at end of year	12.30	3,983,245

The following summarizes information about outstanding options at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 6.06 - $ 8.07	8,509	6.6 years	$ 6.16	8,509	$ 6.16
$ 8.08 - $10.10	1,684,167	7.2 years	$ 9.43	1,684,167	$ 9.43
$10.11 - $12.11	914,240	7.0 years	$ 10.97	914,240	$ 10.97
$12.12 - $14.13	703,543	8.8 years	$ 13.52	703,543	$ 13.52
$14.14 - $16.14	5,042	9.1 years	$ 14.27	5,042	$ 14.27
$16.15 - $18.17	28,364	9.6 years	$ 16.24	14,181	$ 16.24
$18.18 - $20.18	2,580,500	9.8 years	$ 20.18	653,563	$ 20.18
	5,924,365	8.5 years	$ 14.87	3,983,245	$ 12.30

Estimated Fair Value of Grants

Using the Black-Scholes option-pricing model and the following assumptions, the weighted average fair value of option grants was estimated to be $7.30 in 2003, $5.82 in 2002 and $5.21 in 2001. Black-Scholes and alternative option-pricing models do not consider the effects of forfeitability and nontransferability on the valuation of employee stock options.

	2003	2002	2001
Risk-free interest rates	3.1%	3.1%	4.9%
Dividend yield	0.2%	0.2%	0.2%
Weighted average expected lives	4 years	4 years	4 years
Volatility	42%	50%	54%

Pro Forma Effect of Recording Stock-Based Compensation at Estimated Fair Value

The following are pro forma earnings available to common stock and earnings per common share for 2003, 2002 and 2001, as if stock-based compensation had been recorded at the estimated fair value of stock awards at the grant date, as prescribed by SFAS No. 123, *Accounting for Stock-Based Compensation*:

(in thousands, except per share data)

		2003	2002	2001
Earnings available to common stock:				
As reported		$288,279	$186,059	$248,816
Pro forma		$289,311	$183,840	$204,543
Earnings per common share:				
Basic	As reported	$ 1.28	$ 0.89	$ 1.22
	Pro forma	$ 1.29	$ 0.88	$ 1.00
Diluted	As reported	$ 1.27	$ 0.88	$ 1.20
	Pro forma	$ 1.27	$ 0.87	$ 0.98

13. Acquisitions

In April 2003, we entered into a definitive agreement with units of Williams of Tulsa, Oklahoma to acquire natural gas and coal bed methane producing properties in the Raton Basin of Colorado, the Hugoton Field of southwestern Kansas and the San Juan Basin of New Mexico and Colorado for $400 million. The transaction closed in May 2003. After typical closing adjustments, the purchase price was $381 million, which was financed with proceeds from our sale of senior notes (Note 3) and common stock (Note 9).

In June 2003, we entered into an agreement to acquire coal bed methane and natural gas producing properties in the San Juan Basin of New Mexico and Colorado from Markwest Hydrocarbon, Inc. for $60.5 million. After typical closing adjustments and a reduction of $7.9 million withheld for a preferential purchase right, the final purchase price was $51 million, which was funded through bank borrowings. The acquisition was completed in June 2003 and is subject to typical post-closing adjustments.

In October 2003, we announced the completion of property transactions which increased our positions in East Texas, Arkansas and the San Juan Basin of New Mexico for a total cost of $100 million. The purchases were funded with existing credit facilities and are subject to typical post closing adjustments.

In April 2002, we entered agreements to purchase properties in East Texas, Louisiana and the San Juan Basin of New Mexico with a total cost of $144 million. These purchases, funded by our sale of senior notes in April 2002, were as follows:

- Properties in the Powder River Basin of Wyoming from CMS Oil and Gas Co., a subsidiary of CMS Energy Corporation, for $101 million in May 2002,

- An exchange of the above Powder River Basin properties with Marathon Oil Company (Marathon), for gas-producing properties in East Texas and Louisiana in May 2002, and

- Gas-producing properties in the San Juan Basin of New Mexico from Marathon for $43 million in July 2002.

In December 2002, we acquired from J. M. Huber Corporation coal bed methane gas-producing properties in the San Juan Basin of southwestern Colorado for $153.8 million funded with bank debt.

Acquisitions were recorded using the purchase method of accounting. The following presents unaudited pro forma results of operations for 2003 and 2002, as if the Williams, Marathon and Huber acquisitions were made at the beginning of each period. These pro forma results are not necessarily indicative of future results.

(in thousands, except per share data)	Pro Forma (Unaudited) Year Ended December 31	
	2003	2002
Revenues	$ 1,230,967	$ 895,065
Net income before cumulative effect of accounting change	$ 292,989	$ 175,884
Net income	$ 294,768	$ 175,884
Earnings per common share:		
Basic	$ 1.31	$ 0.84
Diluted	$ 1.29	$ 0.83
Weighted average shares outstanding	224,749	208,375

In January 2004, we acquired producing properties located primarily in East Texas and northern Louisiana for $243 million after adjustments of $6 million for net revenues, preferential right elections and other items from the effective date of the transaction. The acquisitions were funded with a portion of the proceeds from the sale of 4.9% senior notes in January 2004 (Note 3).

On February 23, 2004, we announced that we entered into agreements with multiple parties to acquire producing properties located primarily in the Barnett Shale of North Texas and in the Arkoma Basin for $200 million. The majority of the acquisitions are scheduled to close on or before April 15, 2004 and are subject to typical closing and post-closing adjustments. Funding will be provided by bank debt and cash flow.

14. Cross Timbers Royalty Trust Distribution

In August 2003, our Board of Directors declared a dividend of 0.0059 units of Cross Timbers Royalty Trust for each share of our common stock outstanding on September 2, 2003. This dividend, totaling 1,360,000 trust units, was distributed on September 18, 2003, after which we no longer own any Cross Timbers Royalty Trust units.

We recorded this dividend at $28.2 million, the fair market value of the units based on the September 18, 2003 average high and low New York Stock Exchange trade price of $20.70. After considering the cost of the units, we recorded a gain on distribution of $16.2 million.

15. Quarterly Financial Data *(Unaudited)*

The following are summarized quarterly financial data for the years ended December 31, 2003 and 2002:

(in thousands, except per share data)	Quarter			
	1st	2nd	3rd	4th
2003				
Revenues	$ 253,484	$ 282,159	$ 322,058	$ 331,854
Gross profit *(a)*	$ 125,532	$ 140,274	$ 172,789	$ 170,744
Net income	$ 66,230	$ 57,335	$ 102,806	$ 61,908
Earnings per common share:				
Basic	$ 0.31	$ 0.25	$ 0.45	$ 0.27
Diluted	$ 0.31	$ 0.25	$ 0.44	$ 0.26
Average shares outstanding	211,697	225,206	229,740	232,073
2002				
Revenues	$ 179,964	$ 189,151	$ 201,708	$ 239,340
Gross profit *(a)*	$ 92,962	$ 88,782	$ 100,812	$ 128,390
Net income	$ 45,068	$ 34,610	$ 50,293	$ 56,088
Earnings per common share:				
Basic	$ 0.22	$ 0.17	$ 0.24	$ 0.27
Diluted	$ 0.22	$ 0.16	$ 0.24	$ 0.26
Average shares outstanding	206,367	206,835	209,043	211,196

(a) Operating income before general and administrative expense.

16. Supplementary Financial Information for Oil and Gas Producing Activities *(Unaudited)*

All of our operations are directly related to oil and gas producing activities located in the United States.

Costs Incurred Related to Oil and Gas Producing Activities

The following table summarizes costs incurred whether such costs are capitalized or expensed for financial reporting purposes:

(in thousands)	2003	2002	2001
Acquisitions:			
Producing properties	$ 623,775	$ 354,110	$ 238,041
Undeveloped properties	5,678	3,977	3,980
Development *(a)*	460,241	354,083	385,479
Exploration:			
Geological and geophysical studies	639	792	2,123
Dry hole expense	26	242	2,189
Rental expense and other	1,146	1,152	1,126
Asset retirement obligation accrual:			
As of January 1, 2003 *(b)*	75,256	-	-
For the year ended December 31, 2003 *(c)*	13,879	-	-
Total	$ 1,180,640	$ 714,356	$ 632,938

(a) Includes capitalized interest of $2.2 million in 2003, $4.3 million in 2002 and $6.6 million in 2001.

(b) Recorded upon adoption of SFAS No. 143 on January 1, 2003.

(c) Recorded upon acquiring and drilling wells in 2003, as required by SFAS No. 143.

Proved Reserves

Our proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

Standardized Measure

The standardized measure of discounted future net cash flows ("standardized measure") and changes in such cash flows 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 year-end estimated proved reserves. Year-end prices are not adjusted for the effect of hedge derivatives. Discounted future net cash flows are calculated using a 10% rate. Estimated future income taxes are calculated by applying year-end statutory rates to future pre-tax net cash flows, less the tax basis of related assets and applicable tax credits.

As of December 31, 2003, estimated well abandonment costs, net of salvage, are deducted from the standardized measure using year-end costs. Such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired (Note 5).

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

(in thousands)	Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)
Proved Reserves			
December 31, 2000	1,769,683	22,012	58,445
Revisions	(96,990)	(2,193)	(4,201)
Extensions, additions and discoveries	469,602	2,081	3,317
Production	(152,178)	(1,601)	(4,978)
Purchases in place	248,339	-	1,484
Sales in place	(2,978)	-	(18)
December 31, 2001	2,235,478	20,299	54,049
Revisions	76,400	2,433	5,465
Extensions, additions and discoveries	426,541	2,395	1,144
Production	(187,583)	(1,850)	(4,757)
Purchases in place	330,387	2,156	449
Sales in place	(42)	-	(1)
December 31, 2002	2,881,181	25,433	56,349
Revisions	(11,644)	5,487	1,792
Extensions, additions and discoveries	559,773	1,610	424
Production	(243,979)	(2,359)	(4,724)
Purchases in place	465,732	4,508	2,204
Sales in place	(6,824)	(1)	(614)
December 31, 2003	3,644,239	34,678	55,431

(in thousands)	Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)
Proved Developed Reserves			
December 31, 2000	1,328,953	16,448	46,334
December 31, 2001	1,452,222	14,774	41,231
December 31, 2002	2,042,661	19,367	47,178
December 31, 2003	2,651,259	28,187	47,882

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves *(in thousands)*	December 31 2003	2002	2001
Future cash inflows	$ 23,213,223	$ 14,734,787	$ 6,366,557
Future costs:			
Production	(5,207,502)	(3,518,614)	(1,989,344)
Development	(875,665)	(687,723)	(620,611)
Future net cash flows before income tax	17,130,056	10,528,450	3,756,602
Future income tax	(5,292,609)	(3,144,235)	(879,874)
Future net cash flows	11,837,447	7,384,215	2,876,728
10% annual discount	(5,709,208)	(3,510,630)	(1,354,679)
Standardized measure *(a)*	$ 6,128,239	$ 3,873,585	$ 1,522,049

(a) Before income tax, the year-end standardized measure (or discounted present value of future net cash flows) was $8.8 billion in 2003, $5.5 billion in 2002 and $1.9 billion in 2001.

Changes in Standardized Measure of Discounted Future Net Cash Flows

(in thousands)

	2003	2002	2001
Standardized measure, January 1	$3,873,585	$1,522,049	$5,262,030
Revisions:			
Prices and costs	1,469,243	2,554,295	(6,285,062)
Quantity estimates	207,955	209,061	173,587
Accretion of discount	338,895	136,924	455,788
Future development costs	(493,856)	(344,531)	(408,772)
Income tax	(961,584)	(1,122,283)	2,278,522
Production rates and other	2,372	821	1,090
Net revisions	563,025	1,434,287	(3,784,847)
Extensions, additions and discoveries	1,114,577	632,200	252,524
Production	(905,910)	(610,064)	(653,626)
Development costs	434,554	326,219	312,435
Purchases in place *(a)*	1,064,533	568,940	148,111
Sales in place *(b)*	(16,125)	(46)	(14,578)
Net change	2,254,654	2,351,536	(3,739,981)
Standardized measure, December 31	$6,128,239 *(c)*	$3,873,585	$1,522,049

(a) Generally based on the year-end present value (at year-end prices and costs) plus the cash flow received from such properties during the year, rather than the estimated present value at the date of acquisition.

(b) Generally based on beginning of the year present value (at beginning of year prices and costs) less the cash flow received from such properties during the year, rather than the estimated present value at the date of sale.

(c) The December 31, 2003 standardized measure includes a reduction of $7 million ($10.8 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2003 includes a long-term liability of $93.4 million for the same asset retirement obligation which was calculated using different cost and present value assumptions as required by SFAS No. 143.

Price and cost revisions are primarily the net result of changes in year-end prices, based on beginning of year reserve estimates. Quantity estimate revisions are primarily the result of the extended economic life of proved reserves and proved undeveloped reserve additions attributable to increased development activity.

Year-end average realized gas prices used in the estimation of proved reserves and calculation of the standardized measure were $5.71 for 2003, $4.41 for 2002, $2.36 for 2001 and $9.55 for 2000. Year-end average realized natural gas liquids prices were $23.17 for 2003, $17.86 for 2002, $8.70 for 2001 and $26.33 for 2000. Year-end average realized oil prices were $30.55 for 2003, $29.69 for 2002, $17.39 for 2001 and $25.49 for 2000. Proved oil and gas reserves at December 31, 2003 include 200,705,000 Mcf of gas and 1,636,000 Bbls of oil and discounted present value before income tax of $426.8 million related to our ownership of approximately 54% of Hugoton Royalty Trust units at December 31, 2003.

INDEPENDENT AUDITORS' REPORTS

To the Board of Directors and Shareholders of
XTO Energy Inc.

We have audited the accompanying consolidated balance sheets of XTO Energy Inc. and its subsidiaries as of December 31, 2003 and 2002, and the related consolidated income statements, statements of cash flows and statements of stockholders' equity for the years then ended. In connection with our audits of the 2003 and 2002 financial statements, we also have audited the 2003 and 2002 financial statement schedules. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. The 2001 financial statements and financial statement schedule of XTO Energy Inc. were audited by other auditors who have ceased operations. Those auditors' report dated March 28, 2002, on those financial statements and financial statement schedule, was unqualified and included an explanatory paragraph that described the Company's change in method of accounting for its derivative instruments and hedging activities as discussed in Note 1 to the financial statements.

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

In our opinion, the 2003 and 2002 consolidated financial statements referred to above present fairly, in all material respects, the financial position of XTO Energy Inc. and its subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the related 2003 and 2002 financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations effective January 1, 2003, in connection with its adoption of Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations."*

KPMG LLP

Dallas, Texas
March 5, 2004

To the Board of Directors and Stockholders of
XTO Energy Inc.

We have audited the accompanying consolidated balance sheets of XTO Energy Inc. and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated income statements, statements of cash flows and stockholders' equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. 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 management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 6 to Consolidated Financial Statements, the Company changed its method of accounting for its derivative instruments and hedging activities effective January 1, 2001, in connection with its adoption of Statement of Financial Accounting Standards No. 133, "*Accounting for Derivative Instruments and Hedging Activities,*" as amended.

ARTHUR ANDERSEN LLP

Fort Worth, Texas
March 28, 2002

The above report of Arthur Andersen LLP ("Arthur Andersen") is a copy of a report previously issued by Arthur Andersen on March 28, 2002. This audit report has not been reissued by Arthur Andersen in connection with this filing on Form 10-K. After reasonable efforts, we have been unable to obtain the consent of Arthur Andersen, our former independent auditors, as to the incorporation by reference of their report for our fiscal years ended December 31, 2001 and 2000 into the Company's previously filed registration statements under the Securities Act of 1933, and we have not filed that consent with this Annual Report on Form 10-K in reliance on Rule 437a of the Securities Act of 1933. Because we have not been able to obtain Arthur Andersen's consent, you will not be able to recover against Arthur Andersen under Section ll of the Securities Act for any untrue statements of a material fact contained in our financial statements audited by Arthur Andersen or any omissions to state a material fact required to be stated therein. For further information, see Exhibit 23.2 to this Annual Report on Form 10-K.

XTO ENERGY INC. **SCHEDULE II**

Consolidated Valuation and Qualifying Accounts

(in thousands)	Balance at Beginning of Period	Additions *(a)*	Deductions *(b)*	Other *(c)*	Balance at End of Period
Year Ended December 31, 2003					
Allowance for doubtful accounts -					
Joint interest and other receivables	$ 5,537	$ 1,319	$ (528)	$ -	$ 6,328
Year Ended December 31, 2002					
Allowance for doubtful accounts -					
Joint interest and other receivables	$ 4,098	$ 980	$ (65)	$ 524	$ 5,537
Year Ended December 31, 2001					
Allowance for doubtful accounts -					
Joint interest and other receivables	$ 3,121	$ 978	$ (1)	$ -	$ 4,098

(a) Additions relate to provisions for doubtful accounts.

(b) Deductions relate to the write-off of accounts receivable deemed uncollectible.

(c) Adjustment related to reclassified account balance of company acquired in 1999.

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, on the 15th day of March 2004.

XTO ENERGY INC.

By BOB R. SIMPSON
Bob R. Simpson, Chairman of the Board
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 15th day of March 2004.

PRINCIPAL EXECUTIVE OFFICERS (AND DIRECTORS)
DIRECTORS

BOB R. SIMPSON
Bob R. Simpson, Chairman of the Board
and Chief Executive Officer

STEFFEN E. PALKO
Steffen E. Palko, Vice Chairman of the Board
and President

WILLIAM H. ADAMS III
William H. Adams III

PHILLIP R. KEVIL
Phillip R. Kevil

JACK P. RANDALL
Jack P. Randall

SCOTT G. SHERMAN
Scott G. Sherman

HERBERT D. SIMONS
Herbert D. Simons

PRINCIPAL FINANCIAL OFFICER

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

PRINCIPAL ACCOUNTING OFFICER

BENNIE G. KNIFFEN
Bennie G. Kniffen, Senior Vice President
and Controller

INDEX TO EXHIBITS

Documents filed prior to June 1, 2001 were filed with the Securities and Exchange Commission under our prior name, Cross Timbers Oil Company.

Exhibit No.	Description	Page
3.1	Restated Certificate of Incorporation of the Company, as restated on August 22, 2001 (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-3, File No. 333-71762)	
3.2	Amended Bylaws of the Company	
4.1	Form of Indenture for Senior Debt Securities dated as of April 23, 2002 between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8-K filed April 17, 2002)	
4.2	First Supplemental Indenture dated as of April 23, 2002, between the Company and the Bank of New York, as Trustee for the 7½% Senior Notes due April 15, 2012 (incorporated by reference to Exhibit 4.2 to Form 10-K for the year ended December 31, 2002)	
4.3	Preferred Stock Purchase Rights Agreement between the Company and ChaseMellon Shareholder Services, LLC (incorporated by reference to Exhibit 4.1 to Form 8-A/A filed September 8, 1998)	
4.4	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, dated August 25, 1998 (incorporated by reference to Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2000)	
4.5	Registration Rights Agreement among the Company and partners of Cross Timbers Oil Company, L.P. (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S-1, File No. 33-59820)	
4.6	Indenture dated as of April 23, 2003, between the Company and the Bank of New York, as Trustee for the 6¼% Senior Notes due April 15, 2013 (incorporated by reference to Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2003)	
4.7	Registration Rights Agreement dated April 23, 2003, between the Company and certain Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to Form 10-Q for the quarter ended March 31, 2003)	
4.8	Indenture for Senior Debt Securities dated as of January 22, 2004, between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8-K filed January 16, 2004)	
4.9	First Supplemental Indenture dated as of January 22, 2004, between the Company and the Bank of New York for the 4.9% senior notes due February 1, 2014 (incorporated by reference to Exhibit 4.3.2 to Form 8-K filed January 16, 2004)	
10.1 *	Amended and Restated Employment Agreement between the Company and Bob R. Simpson, dated May 17, 2000 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2000)	

Exhibit No.	Description	Page
10.2 *	Amendment to Amended and Restated Employment Agreement between the Company and Bob R. Simpson, dated August 20, 2002 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2002)	
10.3 *	Amended and Restated Employment Agreement between the Company and Steffen E. Palko, dated May 17, 2000 (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2000)	
10.4 *	Amendment to Amended and Restated Employment Agreement between the Company and Steffen E. Palko, dated August 20, 2002 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2002)	
10.5 *	1998 Stock Incentive Plan, as amended August 19, 2003 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2003)	
10.6 *	Amended Employee Severance Protection Plan, as amended February 15, 2000 (incorporated by reference to Exhibit 10.14 to Form 10-K for the year ended December 31, 1999)	
10.7 *	Amendment to Amended Employee Severance Protection Plan, as amended August 20, 2002 (incorporated by reference to Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2002)	
10.8 *	Amended and Restated Management Group Employee Severance Protection Plan, as amended February 15, 2000 (incorporated by reference to Exhibit 10.13 to Form 10-K for the year ended December 31, 1999)	
10.9 *	Amendment to Amended and Restated Management Group Employee Severance Protection Plan, as amended August 20, 2002 (incorporated by reference to Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2002)	
10.10*	Outside Directors Severance Plan, dated August 20, 2002 (incorporated by reference to Exhibit 10.6 to Form 10-Q for the quarter ended September 30, 2002)	
10.11*	Form of Agreement for Grant of Performance Shares (relating to change in control) between the Company and each of Bob R. Simpson and Steffen E. Palko dated February 20, 2001 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2001)	
10.12*	Form of Agreement for Grant of Performance Shares (relating to change in control) between the Company and each of Louis G. Baldwin, Keith A. Hutton and Vaughn O. Vennerberg II dated February 20, 2001 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2001)	
10.13*	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Bob R. Simpson dated May 24, 2001 (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2001)	
10.14 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Steffen E. Palko dated May 24, 2001 (incorporated by reference to Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2001)	

Exhibit No.	Description	Page
10.15 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Louis G. Baldwin dated May 24, 2001 (incorporated by reference to Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2001)	
10.16 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Keith A. Hutton dated May 24, 2001 (incorporated by reference to Exhibit 10.6 to Form 10-Q for the quarter ended September 30, 2001)	
10.17 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Vaughn O. Vennerberg II dated May 24, 2001 (incorporated by reference to Exhibit 10.7 to Form 10-Q for the quarter ended September 30, 2001)	
10.18	Five-Year Revolving Credit Agreement dated February 17, 2004, between the Company and certain commercial banks named therein	
12.1	Computation of Ratio of Earnings to Fixed Charges	
21.1	Subsidiaries of XTO Energy Inc.	
23.1	Consent of KPMG LLP	
23.2	Notice Regarding Consent of Arthur Andersen LLP	
23.3	Consent of Miller and Lents, Ltd.	
31	Rule 13a-14(a)/15d-14(a) Certifications	
	31.1 Chief Executive Officer Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
	31.2 Chief Financial Officer Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
	32 Section 1350 Certifications	
	32.1 Chief Executive Officer and Chief Financial Officer Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	

* Management contract or compensatory plan

Copies of the above exhibits not contained herein are available, at the cost of reproduction, to any security holder upon written request to the Secretary, XTO Energy Inc., 810 Houston Street, Fort Worth, Texas 76102.

CERTIFICATIONS

I, Bob R. Simpson, Chief Executive Officer of XTO Energy Inc., certify that:

1. I have reviewed this annual report on Form 10-K of XTO Energy Inc.;

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

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

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

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: March 15, 2004

BOB R. SIMPSON

Bob R. Simpson
Chief Executive Officer

CERTIFICATIONS

I, Louis G. Baldwin, Chief Financial Officer of XTO Energy Inc., certify that:

1. I have reviewed this annual report on Form 10-K of XTO Energy Inc.;

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

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

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

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: March 15, 2004

LOUIS G. BALDWIN

Louis G. Baldwin
Chief Financial Officer