Success is in the DETAILS

The 2002 XTO Energy Annual Report

For XTO Energy, the plan is simple: demand profitable growth through drilling and acquisitions. We acquire the best producing properties, apply our talent and make them even better by keeping costs low and returns high.

Quality + Discipline + Consistency =

SUCCESS

Successful execution of this strategy requires dedication to all aspects of our business. Every path is pursued. No rock is left unturned. We engage the details with enthusiasm, believing the last 10% makes the distinction.

2002 highlights

In thousands except production, per share and per unit data	2002	2001	2000	1999
FINANCIAL				
Total revenues	$ 810,163	$ 838,748	$ 600,851	$ 341,295
Income before income tax, minority interest and cumulative effect of accounting change	$ 286,749 [a]	$ 455,357 [b]	$ 176,432 [c]	$ 70,605 [d]
Income before cumulative effect of accounting change	$ 186,059 [a]	$ 293,405 [b]	$ 116,993 [c]	$ 46,743 [d]
Earnings available to common stock	$ 186,059 [a]	$ 248,816 [b e]	$ 115,235 [c]	$ 44,964 [d]
Per common share [f]				
Basic	$ 1.12	$ 1.52 [g]	$ 0.81	$ 0.32
Diluted	$ 1.10	$ 1.50 [g]	$ 0.77	$ 0.32
Operating cash flow [h]	$ *515,904*	$ *549,567*	$ 344,638	$ 132,683
Operating cash flow per share [f,i]	$ 3.06	$ 3.31	$ 2.28	$ 0.90
Total assets	$2,648,193	$2,132,327	$1,591,904	$1,477,081
Long-term debt				
Senior	$ 955,000	$ 556,000	$ 469,000	$ 684,100
Subordinated notes and other	$ 163,170	$ 300,000	$ 300,000	$ 307,000
Total stockholders' equity	$ 907,786	$ 821,050	$ 497,367	$ 277,817
Common shares outstanding at year-end [f]	169,302	165,030	155,112	146,667
PRODUCTION				
Daily Production				
Oil (Bbls)	13,033	13,637	12,941	14,006
Gas (Mcf)	513,925	416,927	343,871	288,000
Natural gas liquids (Bbls)	5,068	4,385	4,430	3,631
Mcfe	622,532	525,062	448,098	393,826
Average Price				
Oil (per Bbl)	$ 24.24	$ 23.49	$ 27.07	$ 16.94
Gas (per Mcf)	$ 3.49	$ 4.51	$ 3.38	$ 2.13
Natural gas liquids (per Bbl)	$ 14.31	$ 15.41	$ 19.61	$ 11.80
PROVED RESERVES				
Oil (Bbls)	56,349	54,049	58,445	61,603
Gas (Mcf)	2,881,181	2,235,478	1,769,683	1,545,623
Natural gas liquids (Bbls)	25,433	20,299	22,012	17,902
Mcfe	3,371,873	2,681,566	2,252,425	2,022,653
STOCK PRICE [f]				
High	$ 19.79	$ 16.30	$ 14.50	$ 5.04
Low	$ 11.02	$ 9.23	$ 2.52	$ 1.52
Close	$ 18.53	$ 13.13	$ 13.88	$ 3.02
Cash dividends per share	$ .030	$ .028	$ .017	$ .013
Average daily trading volume	922,710	1,314,676	1,103,794	581,475

a) *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.*

b) *Includes pre-tax effects of a derivative fair value gain of $54.4 million and non-cash incentive compensation of $9.6 million.*

c) *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.*

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

e) *Includes an after-tax charge of $44.6 million for the cumulative effect of accounting change.*

f) *Adjusted for the three-for-two stock splits effected on September 18, 2000 and June 5, 2001 and the four-for-three stock split effected on March 18, 2003.*

g) *Before cumulative effect of accounting change, earnings per share were $1.79 basic and $1.77 diluted.*

h) *Defined as cash provided by operating activities before changes in operating assets and liabilities and exploration expense. Because of exclusion of changes in operating assets and liabilities and exploration expense, this cash flow statistic is different from cash provided by operating activities, as is disclosed under generally accepted accounting principles and reconciled to operating cash flow as follows:*

	2002	2001	2000	1999
Cash provided by operating activities	$ 490,842	$ 542,615	$ 377,421	$ 133,301
Changes in operating assets and liabilities	22,876	1,514	(33,830)	(1,522)
Exploration expense	2,186	5,438	1,047	904
Operating cash flow	$ *515,904*	$ *549,567*	$ 344,638	$ 132,683

We believe operating cash flow is a better liquidity indicator for oil and gas producers because of the adjustments made to cash provided by operating activities, explained as follows:

- *Adjustment for changes in operating assets and liabilities eliminates fluctuations related to the timing of cash receipts and disbursements, which can vary from period-to-period because of conditions we cannot control (for example, the day of the week on which the last day of the period falls), and results in attributing cash flow to operations of the period that provided the cash flow.*
- *Adjustment for exploration expense is to provide an amount comparable to operating cash flow for full cost companies and to eliminate the effect of a discretionary expenditure that is part of our capital budget.*

i) *Calculated based on weighted average diluted shares outstanding. Based on weighted average basic shares outstanding, operating cash flow per share is $3.09 in 2002, $3.36 in 2001, $2.42 in 2000 and $0.94 in 1999.*

GLOSSARY OF TERMS is located on page 80.

A tried-and-true strategy, dedication and hard work have built a successful company.

1986
Cross Timbers Oil Company is founded in the spring.

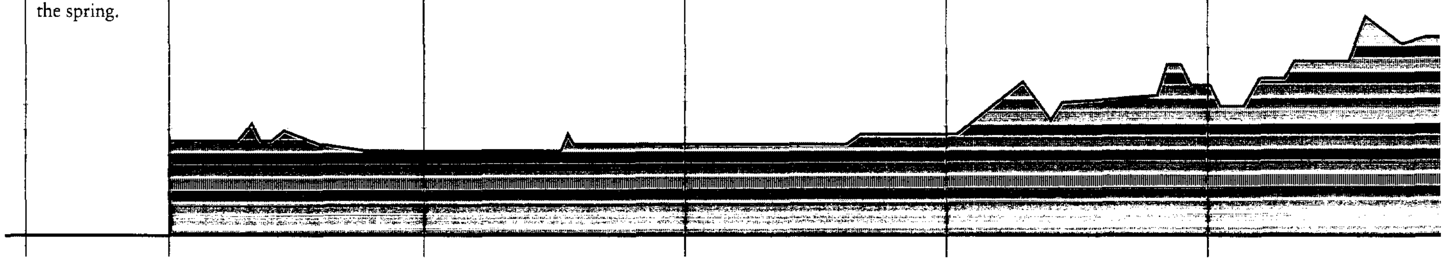
1993
The Company goes public as XTO (NYSE) and ends the year with 296 Bcfe of proved reserves.

1994
XTO acquires Permian Basin assets. Production is up 24% for the year.

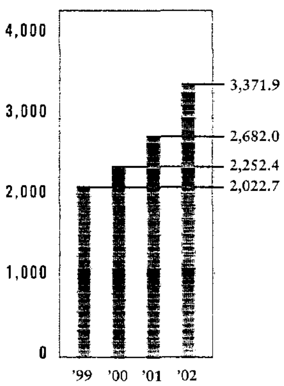
1995
The Company enters the Hugoton Field; now has operations in Texas, Oklahoma, Kansas and New Mexico.

1996
CEO Bob R. Simpson becomes Chairman and focuses XTO on natural gas growth. Proved reserves at year-end hit 795 Bcfe.

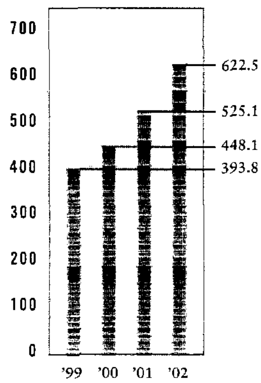
1997
San Juan Basin properties a acquired for $195 million. Production tops 202 Mcfe per day; 3-for-2 stock split



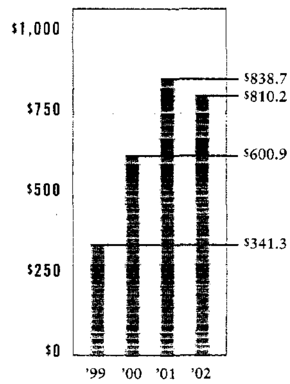
PROVED RESERVES
(in Bcfe)

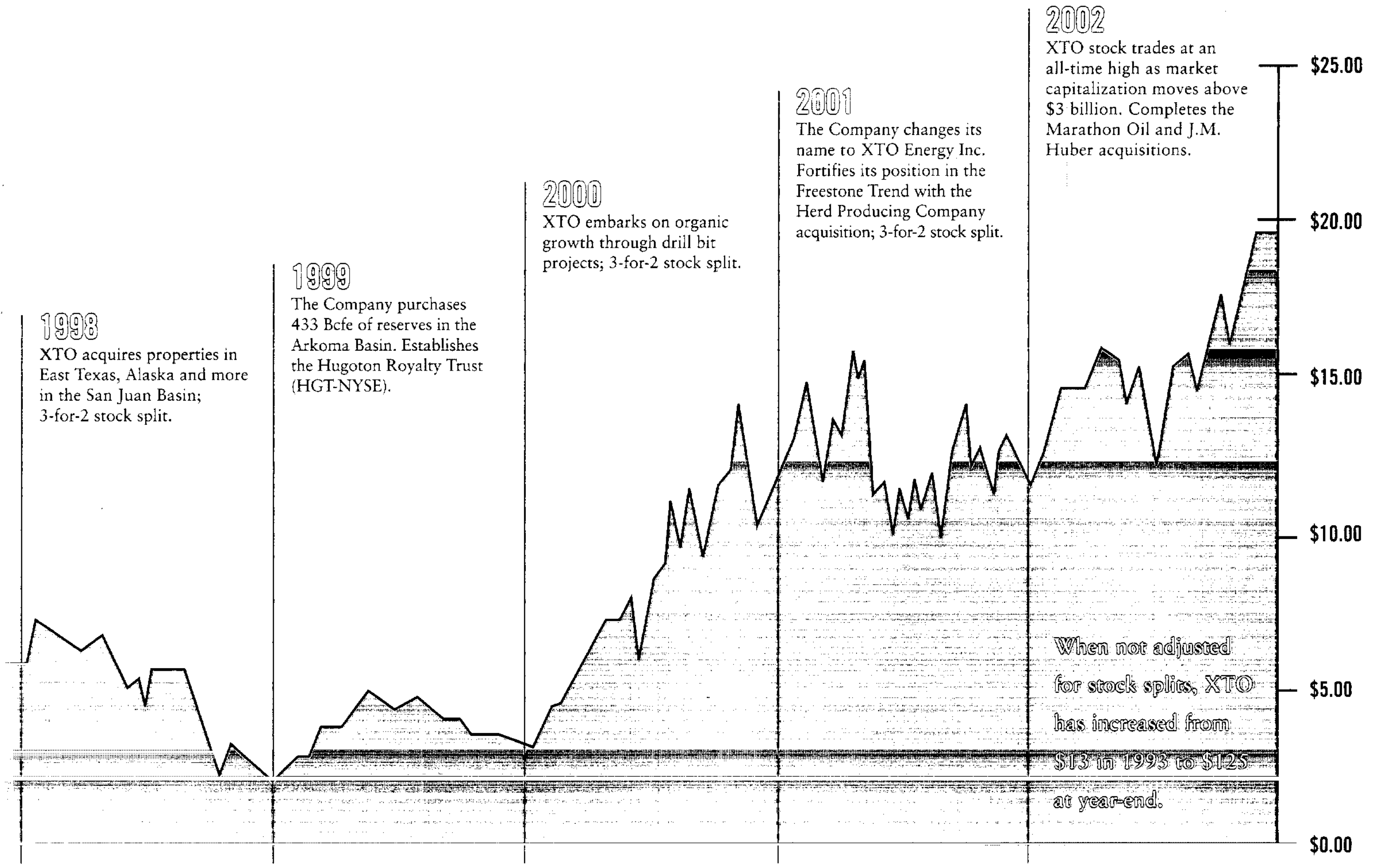


DAILY PRODUCTION
(in MMcfe)

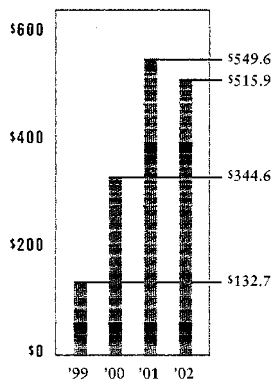


TOTAL REVENUE
(in millions)

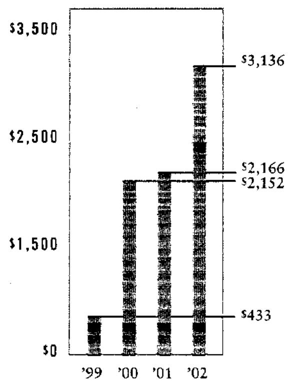




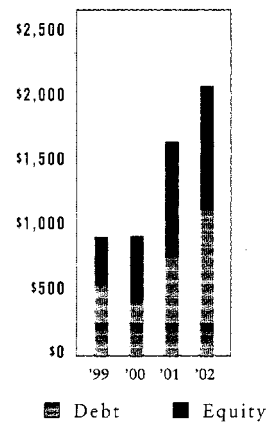
OPERATING CASH FLOW
(in millions)



MARKET CAPITALIZATION
(in millions)



BOOK CAPITALIZATION
(in millions)



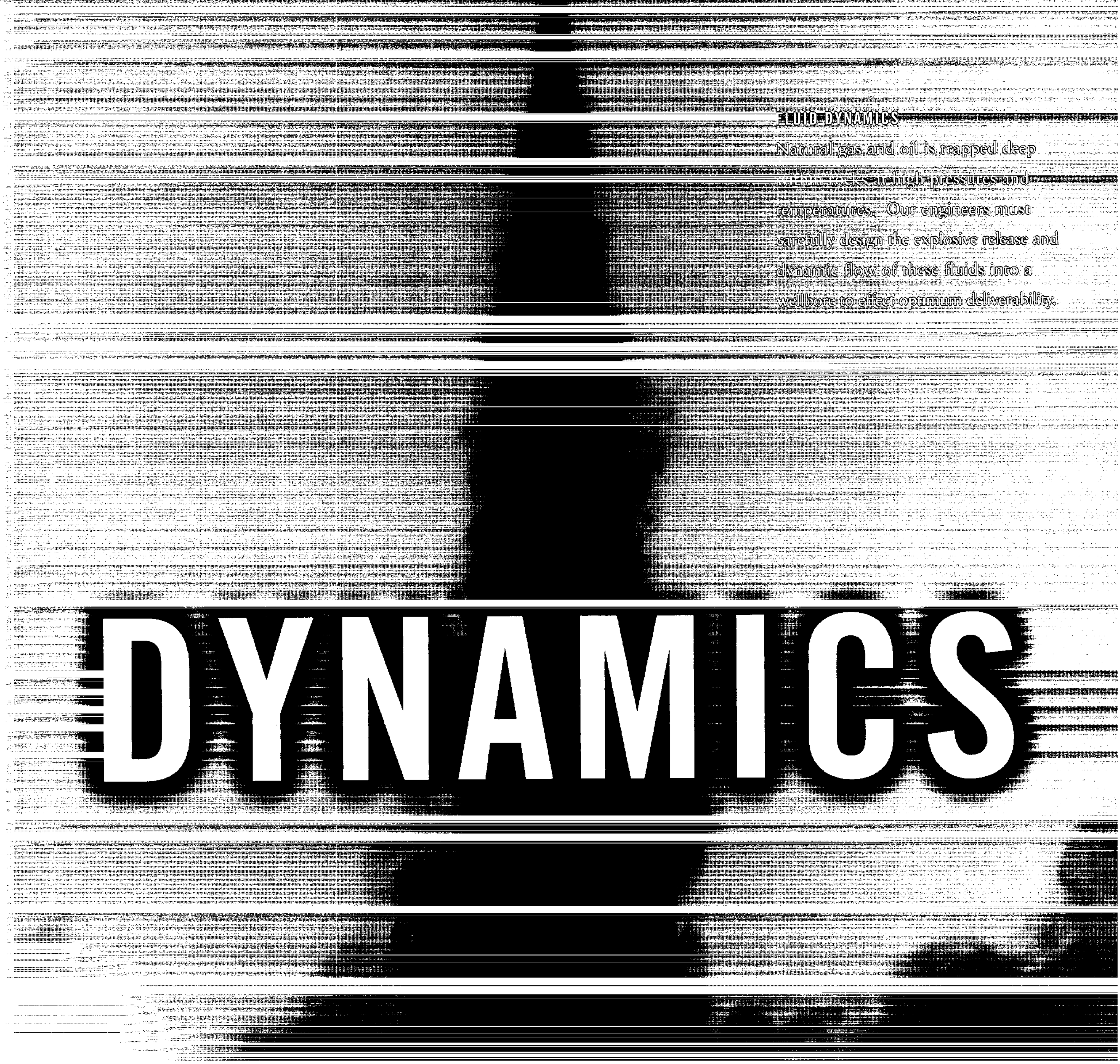
As founders and shareholders, we take pride in our consistent record of creating shareholder value by assessing the ever-volatile energy world and directing sound decisions for XTO.

In a challenging year of market volatility, geopolitical stress, corporate concerns and economic weakness, XTO Energy remained dedicated to executing our business strategy and focusing on the details. As a result, our Company continues to prosper. Across the board, our technical, operational, acquisition and financial teams achieved great things in 2002.

We are proud to recognize the highlights:

- Cash flow from operations totaled $516 million for the year, beating our $450 million target.
- Daily gas production averaged 514 MMcf, a 23% increase above 2001 levels.
- Proved reserves grew to 3.37 Tcfe, of which 85% is natural gas. This surpassed our goal by more than 10%.
- We replaced 404% of production volumes at a cost of only $.78 per Mcfe.
- Our acquisition team secured strategic property transactions which added 346 Bcfe of long-lived reserves in core operating areas.
- The underlying value of our Company grew as reserves increased more than 20% to 20 Mcfe per share with debt remaining relatively flat at $.33 per Mcfe.
- For our investors, the market value of XTO's shares appreciated $970 million during 2002.

Perhaps most importantly, these achievements lead the way to strong financial and operational performances in 2003. The Company now owns the richest inventory of development properties in its history - recognized upsides of 2 Tcfe - enough to grow production for many years. These opportunities are low risk exploitation events, consistent with the same technical and operating structure that defines our history. This means XTO Energy will continue to deliver on its predictable growth strategy even as overall risk for the E&P sector gravitates toward higher costs, fewer domestic prospects and diminishing production volumes.

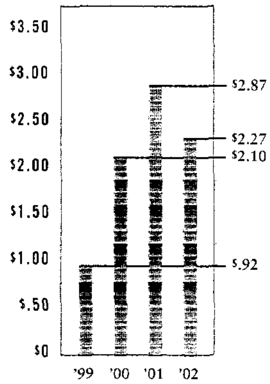


FLUID DYNAMICS

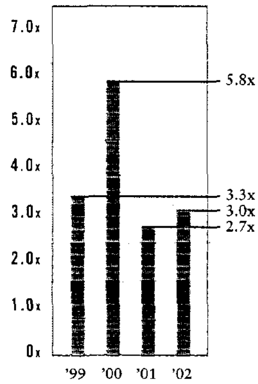
Natural gas and oil is trapped deep within rocks at high pressures and temperatures. Our engineers must carefully design the explosive release and dynamic flow of these fluids into a wellbore to effect optimum deliverability.

DYNAMICS

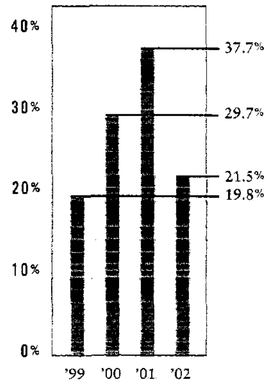
OPERATING CASH FLOW MARGIN
(per Mcfe)



REPLACEMENT EFFICIENCY
(Operating cash flow per Mcfe / Replacement cost per Mcfe)



RETURN ON EQUITY
(%)



MEASURED GROWTH

Management's top priority is to create shareholder value through growth over the long term, achieving a reliable production profile, solid economic returns and a strong balance sheet. Our foundation for this extended growth is the Company's underlying base of long-lived reserves.

XTO Energy is a sector leader in internal production growth, value creation and shareholder returns.

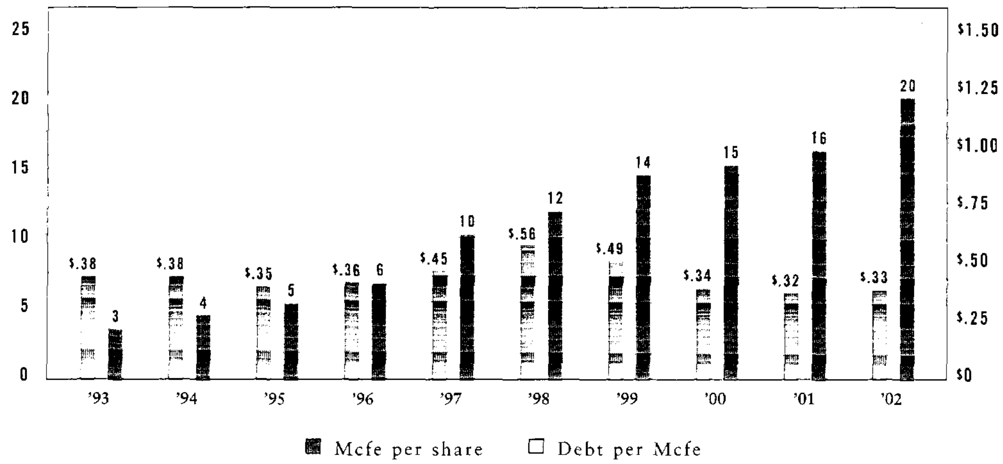
In a depleting resource business, a shallow decline curve on existing production is of utmost importance, because less production must be replaced before building incremental volume growth. With shallow declines, we are afforded the time to comprehensively assess our properties and identify new opportunities, all the while realizing strong cash flow. This process leads to more inventory, which in turn promotes further growth. Ultimately, XTO benefits through a constant process of organic growth and by the acquisition of long-lived producing properties that replenish our organic growth opportunities. We grow in a step by step fashion ... measured growth.

Equally as significant, the nature of measured growth coupled with price hedging leads to healthy economic returns. Development inventory is low risk, reliable and predictable. Finding costs are effectively managed and operating costs are kept low.

As noted in the charts above, XTO's strong operating cash flow margin and low finding costs lead to a replacement efficiency of 3-to-1, top-tier performance in the energy complex. Our Company has realized better than $2 in operating cash margin per Mcfe produced over the past three

VALUE CREATION

(Strategic Focus On Profitable Growth per Share)



years, while replacement costs, which include development and acquisition activities, have averaged only $.76 per Mcfe. XTO's financial performance generated a 21.5% return on stockholders' equity (ROE) in a year when many of our peers struggled. In practical terms, we have built a program to deliver consistent growth and profitability.

OPPORTUNITY IN VOLATILITY

In times of uncertainty, focus on what is certain. For XTO, we moderated the volatility of the 2002 energy markets by taking action. With our high margin inventory, we secured gas prices to assure the Company's performance and to deliver on our profitable growth commitment. While most companies were handicapped by low prices, we continued to drill our wells and pursue strategic acquisitions. As a result, our "opportunistic hedging" led to extraordinary economic returns and clear-cut operational advantages.

Resulting operating cash flows at our $3.49 per Mcf realized gas price far exceeded the capital needed to assure double-digit internal growth. The additional cash, along with our growing equity base, provided the flexibility to acquire "bolt-on" properties in East Texas and the San Juan Basin.

For operational success, a consistent hedging program is critical to maintain ongoing operations. For more than two years, XTO has maintained an active drilling program. Overall efficiency has significantly improved. Costs have dropped. As a result, new drilling and workover opportunities have expanded our asset base. We have kept our employees working hard, our vendor relationships solid and our growth profile building.

XTO Energy has identified about 2 Tcfe of low risk drilling upsides for development representing more than 60% of its proven reserves base.

DELIVERING STRONG PERFORMANCE

The Company enjoyed another banner year of financial and operational results in 2002. Cash flow from operations totaled $515.9 million, with realized natural gas prices averaging $3.49 per Mcf, a decrease of only 6% from 2001 when our gas prices averaged a record $4.51 per Mcf. The Company reported earnings available to common stock of $186.1 million, or $1.12 per share, compared with $248.8 million, or $1.52 per share in 2001. With higher production volumes leading the way, our revenues hit $810.2 million in 2002, down only 3% in spite of the 23% drop in gas prices.

We will continue our commitment to low risk, predictable growth, delivering solid economic returns along the way.

When translated to the public markets, these results drove our stock price up 41% for the year, a top performance in our sector. Over the last four years, XTO Energy has appreciated in market value by a remarkable 514%, rewarding shareholders for the extraordinary value which has been created.

A CONFIDENT OUTLOOK

Simply stated, we are poised for a strong future with natural gas. Domestic gas production is declining steadily with no short-term solution. Natural gas storage levels drained quickly in early 2003, pushing prices to premium levels. With drilling low and demand on the rise, gas has now reached a condition of scarcity. Our industry will be technically challenged to meet the demand for gas. As we are now witnessing, a natural gas price well above $4 per Mcf will be needed to justify the risk of exploration and to allocate existing supply of a scarce commodity.

In this environment, XTO is well-positioned with our low risk drilling inventory and we are set to deliver another record year in production and proved reserves growth in 2003. We foresee natural gas production increasing by 15% to 17% while targeting a record $600 million in operating cash flow. Our strong balance sheet positions XTO to be opportunistic and acquire producing properties if the right ones become available. All the while, we will maintain our dedicated focus on the details ... cost management, technical excellence and judicious hedging to maximize shareholder returns.

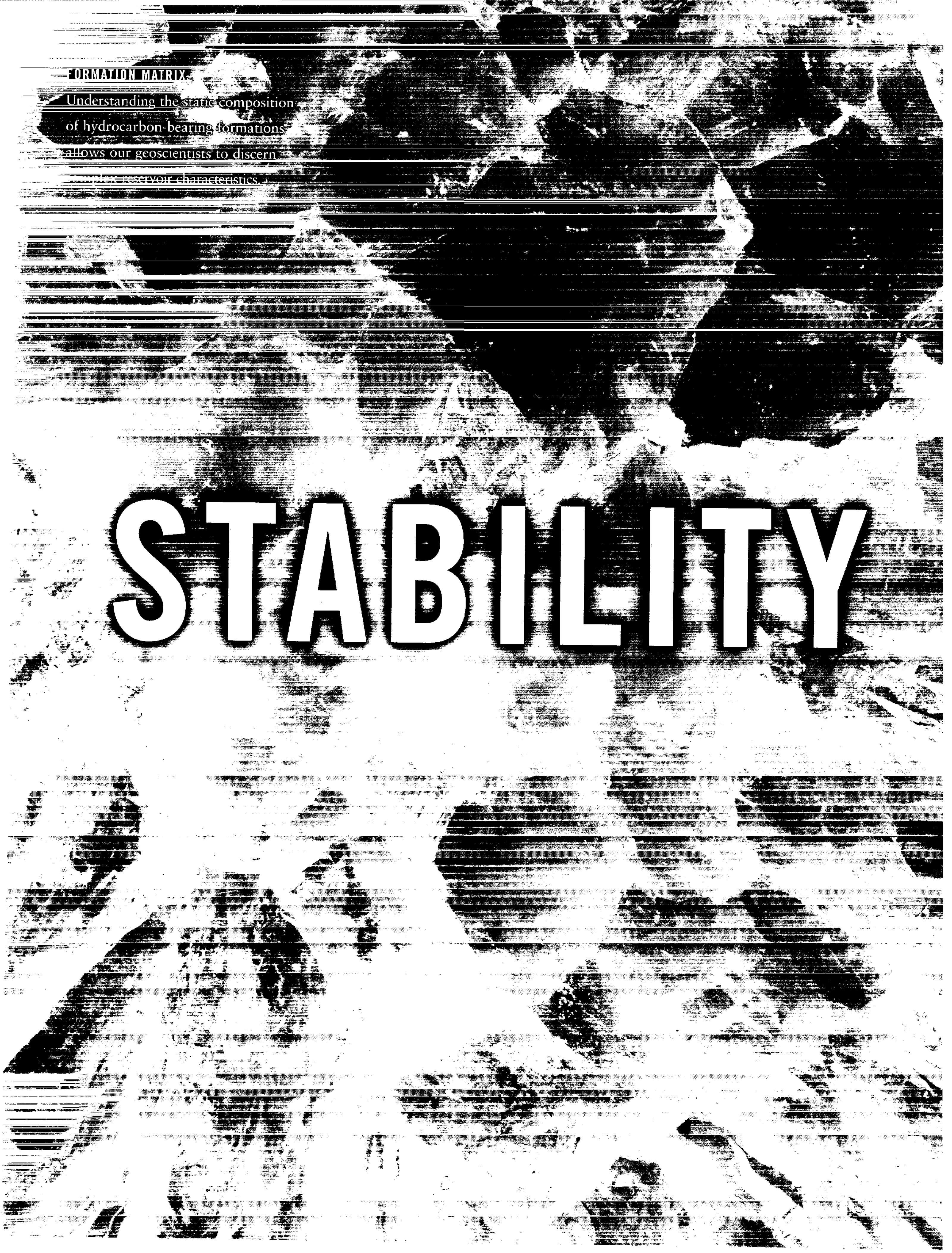
Our senior management team has now worked together for over 25 years, adapting tough challenges into business opportunities. As your leaders and fellow shareholders, we are proud of the Company's achievements. In the coming years, we look forward to directing XTO Energy as a premium investment.

As always, we thank our employees and Board of Directors for their tremendous dedication and our shareholders for their continuing support.

BOB R. SIMPSON
Chairman and
Chief Executive Officer

STEFFEN E. PALKO
Vice Chairman
and President

March 31, 2003



FORMATION MATRIX

Understanding the static composition of hydrocarbon-bearing formations allows our geoscientists to discern complex reservoir characteristics.

STABILITY

XTO Energy is built on a foundation of high margin assets. These properties allow for long-term profitable growth. With quality comes confidence and stability.

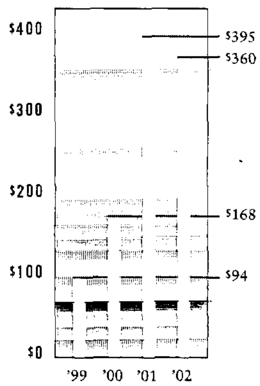
XTO Energy has remained true to its founding strategy. We identify and acquire high quality producing properties; then, we strive to enhance their value by increasing production and reserves. Simple enough in theory, but a challenge to realize.

For over 16 years, our technical and operational teams have tackled this challenge with a successful methodology. It starts with the adeptness and patience to buy exactly the right assets. Then, a rigorous process is imposed to discover and recover new hydrocarbons. At XTO, we call it QDC: Quality, Discipline and Consistency. In application, this rigorous process is a comprehensive undertaking of the details.

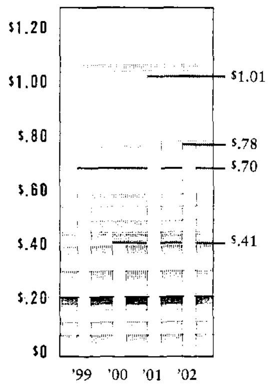
We assess years of technical data, compile a multitude of upside ideas with innovative techniques and then risk the projects to appraise their economic value. Each opportunity from drill well to workover to compression optimization is ranked based on risk and ROR expectations. Our headquarters works in tandem with the operating districts to construct a list of projects, determine their potential and present implementation plans to executive management. Once validated, all projects are combined to create the Company inventory.

This growth inventory is dynamic, meaning priorities are adjusted based on success, commodity prices and cost structure. Our operations team is agile enough to shift capital to most effectively spend our dollars. We don't suffer the big bureaucracy "delay syndrome", nor do we have extensive global offices to compete for available capital. In essence, XTO's domestic focus and tight management control allows for real-time changes in spending decisions, capital deployment and, finally, execution. The results bear out our success.

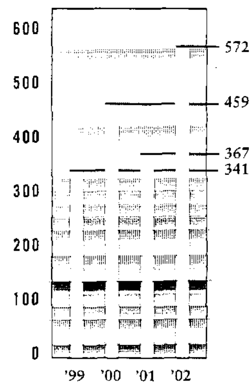
DEVELOPMENT EXPENDITURES
(in millions)



RESERVE REPLACEMENT COST
(per Mcfe)



DEVELOPMENT ADDITIONS
(in Bcfe)



Since inception of the Company in 1986, production volumes have grown at a compound annual rate of 21%. More importantly, our risk profile and strategy have not changed. We exploit in proven producing areas with a success rate of over 95%. Going forward, our development inventory in hand is more of the same. Even while others must seek high risk exploration or international ventures, XTO is set to continue on its course, growing quality reserves with a low risk profile through our QDC process.

DEVELOPMENT ACHIEVEMENTS

During 2002, XTO Energy deployed $360 million in development capital to increase reserves by 572 Bcfe, leading the way to record proved reserves of 3.37 Tcfe. The proved developed producing component equaled 72% of this 2002 total. Inclusive of our "bolt-on" acquisitions, the Company replaced 918 Bcfe or 404% of the year's production at a replacement cost of only $.78 per Mcfe. This achievement highlights our effective development strategy as the comparable finding cost for our peer group totaled more than $1.50 per Mcfe. When focusing on development costs alone, XTO replaced 252% of production at $.63 per Mcfe. Over the past four years, development expenditures have grown four times. Still, our exploitation programs preserved our low cost advantage, replacing an average of 239% of production at $.59 per Mcfe — a leading performance in the industry.

What starts as quality properties with potential opportunities is streamlined into legacy assets with profitable inventory.

ACQUISITION SUCCESS

With ongoing development success, our acquisition efforts have focused on expanding the property base in several core areas of the Company: East Texas, the San Juan Basin and Arkoma. Our technical and operating advantage allows management to aggressively pursue adjacent properties to extend our trends. These "bolt-on" acquisitions provide immediate impact with both long-lived production and upside development opportunities.

During the year, the Company purchased 346 Bcfe of these reserves for $354 million, equating to a purchase price of $1.02 per Mcfe. The initial transaction in May extended productive acreage in our East Texas Freestone Trend by about 40,000 net acres. Along with 28 MMcfe per day of production, this purchase increased our drilling inventory by at least 250 locations in the Freestone Trend. Later in the year, two additional transactions were closed in the San Juan Basin. Together, these properties added about 45 MMcfe per day of shallow decline gas production. The San Juan assets extend XTO's footprint by about 41,000 net acres of highly prolific leasehold. The Company has already identified substantial upsides to add to the San Juan inventory.

2003 PLANS

Our prolific drilling inventory provides XTO with a visible path for internally increasing production. As in the past three years, we are targeting double-digit growth in natural gas production, with only two-thirds of our operating cash flow devoted to achieve this. Using around $400 million and a record 26 drilling rigs, we plan to drill 309 new wells and perform 385 workovers within our existing trends. The resulting finding and development costs are expected to be $.75 to $.85 per Mcfe. To moderate expected cost escalation, the Company has already contracted rates on drilling, tubulars and equipment in most areas. The work program will focus in East Texas with 65% of the budget. The San Juan and Arkoma basins are each allocated about 10% of the funds. Development events in Alaska, the Permian Basin and the Mid-Continent will utilize another $40 million. The remaining $20 million is targeted for exploration activities.

At XTO, we earn our competitive advantage through operational intensity, technical innovation and long hours.

With high commodity prices and the industry facing limited growth options, we expect the acquisition market for quality assets to be very competitive. Fortunately, XTO is well-positioned with multi-year drilling plans and substantial financial flexibility. As always, we will solicit strategic properties that add to core areas and assess larger acquisitions if, and when, they become available.

Layer upon layer, our Company has grown in scale by design. The acquisition and development of choice assets have delivered a long-lived production profile and an expanding inventory of upsides.

EAST TEXAS

The East Texas Basin has long been one of the nation's premier oil and gas provinces. Since first production in the 1920's, the basin has enjoyed decades of "boom times" as advancing technology prompted new discoveries. Like most long-lived, complex productive regions, the basin continues to yield more hydrocarbon reserves than expected. For XTO, owning assets in East Texas was a perfect way to expand our high quality portfolio.

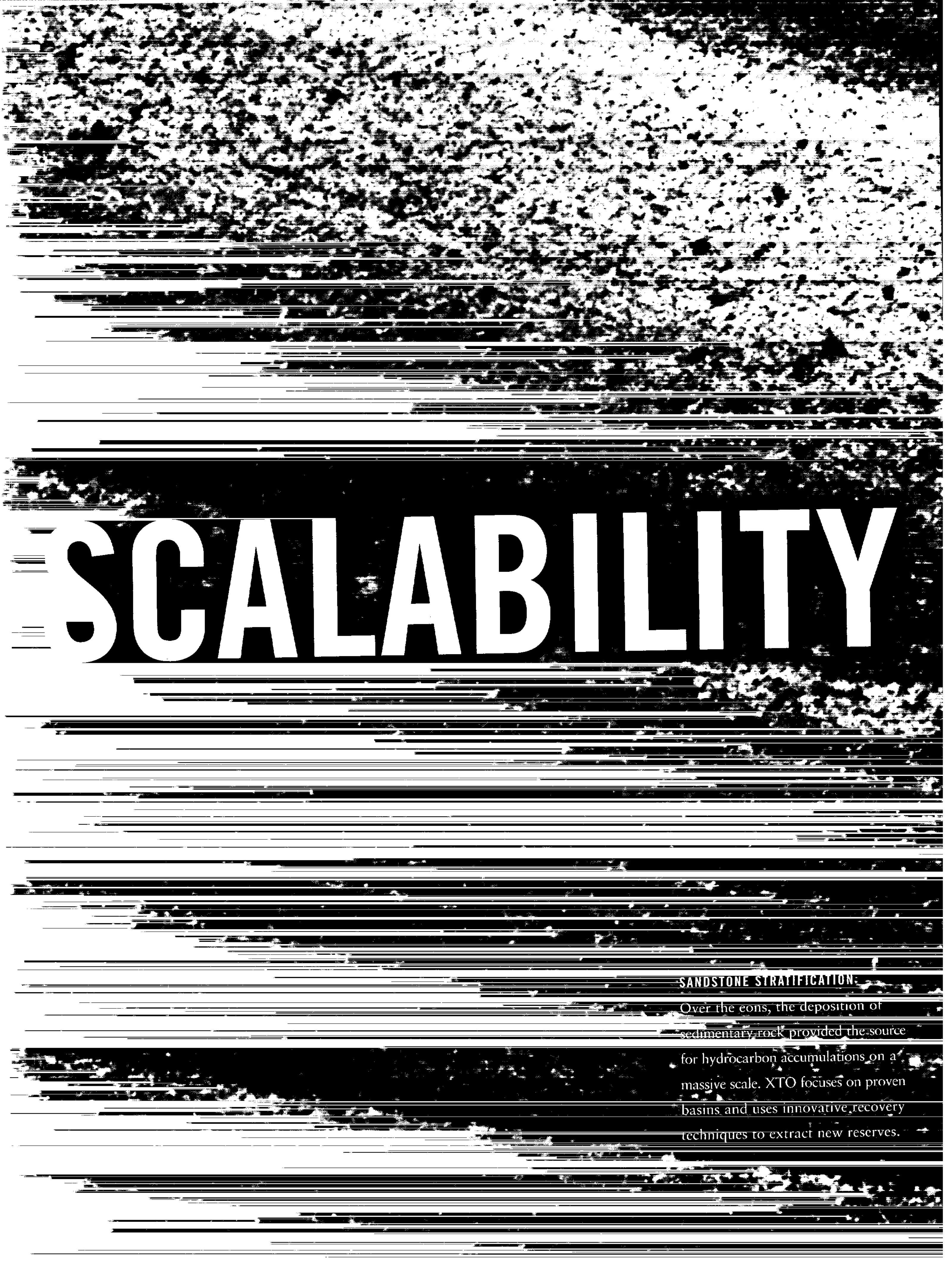
In 1998, the Company purchased interests in eight fields producing about 80 MMcf per day of natural gas on a shallow decline. Proved reserves totaled 251 Bcfe, primarily allocated to the Travis Peak formation, which had already produced almost 2 Tcfe. With producing intervals ranging from depths of 7,000 feet to 13,000 feet, our geologists and engineers believed the leasehold position offered tremendous upside. As it has evolved, the acquisition has become the centerpiece for XTO Energy's growth program.

With our highly successful development plans, the Company has grown its East Texas assets to about 1.6 Tcfe of proved reserves as of year-end. Daily production volumes have now topped 300 MMcf of gas and almost 1,600 barrels of liquids. Our leasehold base has increased to more than 180,000 acres encompassing 17 producing fields. Even more exciting, we now recognize about 1.6 Tcfe of unbooked reserve potential within the development inventory, enough for six years of drilling.

The Freestone Trend

An acquire and exploit company rarely gets noticed for recovering new reserves in existing fields; yet, our success in the deep sediments of East Texas ranks as a major tight-rock discovery. In 2000, after a two-year pilot program, our technical

SCALABILITY



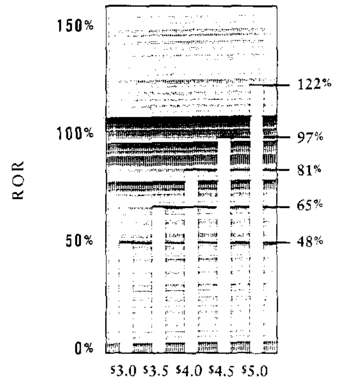
SANDSTONE STRATIFICATION: Over the eons, the deposition of sedimentary rock provided the source for hydrocarbon accumulations on a massive scale. XTO focuses on proven basins and uses innovative recovery techniques to extract new reserves.

teams announced a development initiative based on a structurally defined trend covering nearly 2,000 square miles. At about 2.5 miles deep, the East Texas Freestone Trend includes over 3,000 feet of gas-rich formations: the Cotton Valley Limestone, the Bossier Sands and the Cotton Valley Sands. Historically, these zones had failed to produce commercially except for isolated areas. Porosity and permeability were low and conventional massive sand-fracturing techniques were expensive and failed to release the potential.

By using high rate hydraulic fracturing techniques with low proppant content, our engineers effectively accessed natural gas trapped in tight-rock deposits.

Our geoscientists seized on the opportunity. They designed methods to properly isolate the best sections of these complex intervals. Then, armed with proven well results from Company work in Wyoming and Oklahoma, we utilized fracturing techniques with mostly water to crack the dense matrix. As a result, lateral fractures extended outwards from the wellbore providing maximum length and adequate conductivity, while minimizing fluid damage. The technique not only proved effective but cut completion costs by 50% to 70%. Our team then commingled the completed zones from the deep pay

EAST TEXAS
Freestone Trend Well Economics
(Pre-tax ROR)



intervals to simultaneously produce gas up the same wellbore. As a result, increased production and reserves greatly improved economic viability, paving the way for a large-scale development program.

After 239 wells, the results have proved an exploitation bonanza. The individual zones per well have yielded 1 to 3 Bcf each for a combined average of 3.5 Bcf with an initial daily rate of about 3.5 MMcf. With a gas price of $4 per Mcf, this translates into a NPV-10% of $3.2 million. Given our acquisition acreage and field extensions in 2002, we now have 800 to 1,000 of these locations to drill which could yield a cumulative NPV-10% of over $2 billion for XTO. Furthermore, we are continuing to delineate the productive limits of the Freestone Trend and have not begun to aggressively drill the interior spacing. Our team expects the inventory of low risk locations to build further in 2003 as we validate more extensions and downspace drilling.

DEVELOPMENT HIGHLIGHTS

Even with the substantial inventory, our program pursued "measured growth", delivering steady drilling without overrunning our science and compromising the long-term value of the play. During the year, the Company drilled 137 wells and performed 53 workovers. The majority of the work, more than 120 new wells, focused on the Freestone Trend fields of Freestone, Bald Prairie, Farrar, Oaks, Luna, Teague, Dew and Bear Grass. The productive leasehold comprising the Company's stake in the Freestone Trend increased to over 100,000 net acres from just 65,000 acres in 2001. With our volume growth, XTO's 27-mile pipeline infrastructure, consisting of gathering, processing and compression, is handling about 225 MMcf per day with another 175 MMcf per day of capacity.

In 2003, we plan to drill 149 new wells in the basin with 144 slated to continue the development of the Freestone Trend. A total of 60 workovers and recompletions will be performed during the year.

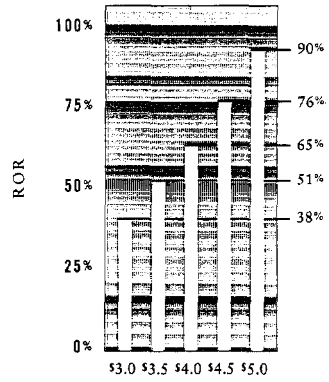
ARKOMA BASIN

The Arkoma, one of the most complex and prolific gas regions in the nation, extends across Arkansas and into Oklahoma. This basin is a highly fractured and faulted province with reservoirs ranging from depths of 2,500 feet to 9,000 feet. Ample natural gas in place has provided for a premier long-lived basin. Yet, the complex geology has proven a challenge to interpret, keeping Arkoma's development inconsistent and overall growth limited. Knowing this, XTO Energy considered the basin a prime candidate for application of our exploitation model and expertise.

ARKOMA BASIN

Fairway Trend Well Economics

(Pre-tax ROR)



In 1999, the Company closed acquisitions which secured a core operating position in the Arkoma Basin. We purchased about 433 Bcfe (net of sales) of shallow decline reserves under more than 430,000 net acres of leasehold. The Company's daily gas production of 100 MMcf immediately cast XTO as the top producer in Arkansas with 40% of the state's production. Furthermore, the low operating costs and high margins provided healthy cash flow from which to fuel growth in the production base.

PRECISION

TECHNICAL ACCURACY

Exact interpretation of logging data allows our geoscience team to isolate the porosity and permeability streaks within complex formations that will produce gas. From this technical perspective, success or failure is a "game of inches."

Over the past three years, our technical teams have taken a patient and steady approach to our development program. A rigorous assessment of regional geology through new seismic data and subsurface interpretation provided a fresh understanding of faulting and depositional patterns in the basin. Potential hydrocarbon traps were identified in our producing fields. In our new drill wells, we utilized formation imaging logs to better define fracture orientation and fault planes. Now with more than 150 new wells drilled and about 200 workovers performed, our geoscientists have designed a "fault-block analysis technique" to determine potential well locations that not only offset productive wells but extend across fault planes. Wellbore data and geologic mapping are used to extrapolate traps within a fault-defined compartment to maximize reservoir recovery. This technique has generated drilling, recompletion and stimulation activities across the basin.

XTO's success begins with acquiring exactly the right asset package. Precision in our evaluation process and agility in negotiation gives us the advantage.

Development Highlights

The Company's exploitation program has increased production by more than 20% since the original acquisition. Of the basin's three principal regions, the Fairway, the Overthrust and the Cromwell/Atoka trends, most development activities have been performed in the Fairway Trend, where 80% of our Arkoma natural gas volumes are produced.

Our operations team used the Aetna and Cecil fields in the Fairway Trend as the case study for designing an effective development model for the basin. Artificial lift and compression enhancements have been successfully introduced where prior operators doubted their viability. Our "fault-block analysis technique" indicated numerous well locations in the two fields. The 40 new wells drilled to date have yielded an average NPV-10% of $1.4 million with net reserves of 1.1 Bcfe and a finding cost of $.65 per Mcf. XTO owns an average interest of 65% in these wells. Older wells have offered more than 50 recompletion opportunities. These workovers have typically added 400 Mcf in daily production and 500 MMcf in reserves at a cost of $.30 per Mcf.

In the Overthrust Trend, XTO has successfully navigated complicated faulting systems to extend production in Chismville, Booneville and Gragg fields. The producing wells range in depth from 3,500 feet to 7,500 feet and offer higher production rates. In 2002, field spacing rules were changed to allow 160-acre development in the Booneville and Chismville fields, substantially increasing XTO's remaining well locations. Downspacing in Gragg Field should soon follow suit.

In the Arkoma, the Company's development plans include approximately 200 new locations set on a drilling pace of 50 to 60 wells per year. Our "fault-block analysis technique" will provide for ongoing inventory increases as we advance the technology across the basin.

The use of formation-imaging well logs has led to more precise interpretation of geology and, ultimately, finding new gas reservoirs.

SAN JUAN BASIN

The San Juan Basin is the second largest onshore natural gas basin in North America. Since production began in 1911, this hydrocarbon-rich province, which includes parts of New Mexico and Colorado, has yielded more than 31 Tcfe. Spanning from depths of 1,500 feet to 10,000 feet, these multiple formations continue to offer opportunities to discover reserves and increase production volumes.

In 1997, XTO Energy secured a foothold in the region with the acquisition of 290 Bcfe in northwestern New Mexico. Reserves have grown steadily to more than 680 Bcfe as the Company's net daily production has increased to about 100 MMcf of gas and about 5,800 barrels of liquids. Perhaps most compelling, XTO continues to expand its development inventory. We exited 2002 with more than 400 drilling locations identified, representing a potential reserve impact of 350 Bcfe.

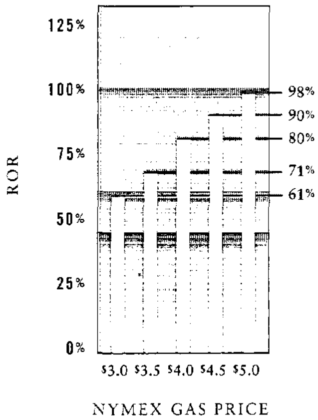
Development Highlights

In 2002, our San Juan workload involved drilling about 50 new wells in the Company's primary producing formations: the Mesaverde, the Dakota and the Fruitland Coal. With the prolific Mesaverde and Dakota reservoirs outperforming expectations throughout the basin, spacing has now been designated at 80-acres for both horizons. This ruling allows XTO to drill another 200 new wells across our leasehold. As done in other areas, we will capture enhanced production and economics by commingling the gas from multiple payzones into a single wellbore. The resulting wells will realize about 1.1 Bcfe net of reserves at a cost of $.60 per Mcfe yielding a NPV-10% of nearly $1.2 million. XTO owns an average interest of 65% in these wells. As a further upside, these wells will be drilled deeper through the Dakota to a new discovery horizon in the Burro Canyon and Morrison sands. To date these "exploration tails" have shown a 20% success rate and have tapped into 2 to 4 Bcfe of reserves with daily rates of 1 to 4 MMcf.

SAN JUAN BASIN

Fruitland Coal Well Economics

(Pre-tax ROR)



Our technique of commingling gas production from multiple reservoirs improves economic returns and lowers execution risk.

Throughout our acreage, the Fruitland Coal continues to provide production growth and extensive upsides for XTO. Our coal bed methane (CBM) daily production rate has increased from 2 MMcf in 1997 to more than 50 MMcf. Our upside inventory holds about 150 coal bed wells based on 160-acre development. The typical well should yield 1.1 Bcfe net to XTO at a cost of $.30 per Mcfe and yield a NPV-10% of $1.5 million. XTO owns an average interest of 75% in these wells. With these exceptional economics, our acquisition team has targeted additional opportunities to further expand the Company's CBM base.

In 2002, our San Juan operations team performed 240 low cost, high return workovers of which 50 were wellhead compressor installations. The 380 compressors now operating have increased production by an average of 100 Mcf per day and increased reserves by about 200 MMcf per well. We are targeting another 50 to 60 compression installations for 2003.

ACQUISITION ASSETS

The long-lived properties in the San Juan Basin are an ideal asset to merge into XTO's drill bit growth program. These natural gas properties provide strong cash flow, shallow decline production and immediate upside potential. During the year, we secured two sets of properties which exceeded our acquisition expectations.

For a total of $196 million, XTO added 212 Bcfe of quality reserves which immediately joined our operations in New Mexico and extended our Fruitland Coal holdings into Colorado. Spread across 88,000 gross acres, XTO purchased interests in 896 wells which added 45 MMcfe in daily production. Given our ongoing development expertise, the technical teams have already identified workovers and new wells which could potentially yield 75% to 100% upside to these purchased reserves. We look to 2003 for more opportunities for "bolt-on" property acquisitions in the basin.

PERMIAN BASIN

XTO Energy owns and operates substantial long-lived oil fields in focused areas of West Texas. These quality assets – University Block 9, the Prentice Northeast Unit and the Cornell Unit of the Wasson Field – generate opportunities to sustain production volumes year after year. As technology improves, the multi-pay complex nature of the basin continues to yield upsides that recover more oil.

Since about 1994, the Company has implemented infill development programs with horizontal and sidetrack drilling techniques to effectively enhance recovery. From the 21 MMBOE purchased on these properties, an additional 34 MMBOE have been developed and booked as reserves or sold as production. During 2002, the Permian Basin properties produced about 8,000 BOPD for the Company. Our ongoing efforts have identified new pay intervals in the fields which hold further upsides for future exploitation.

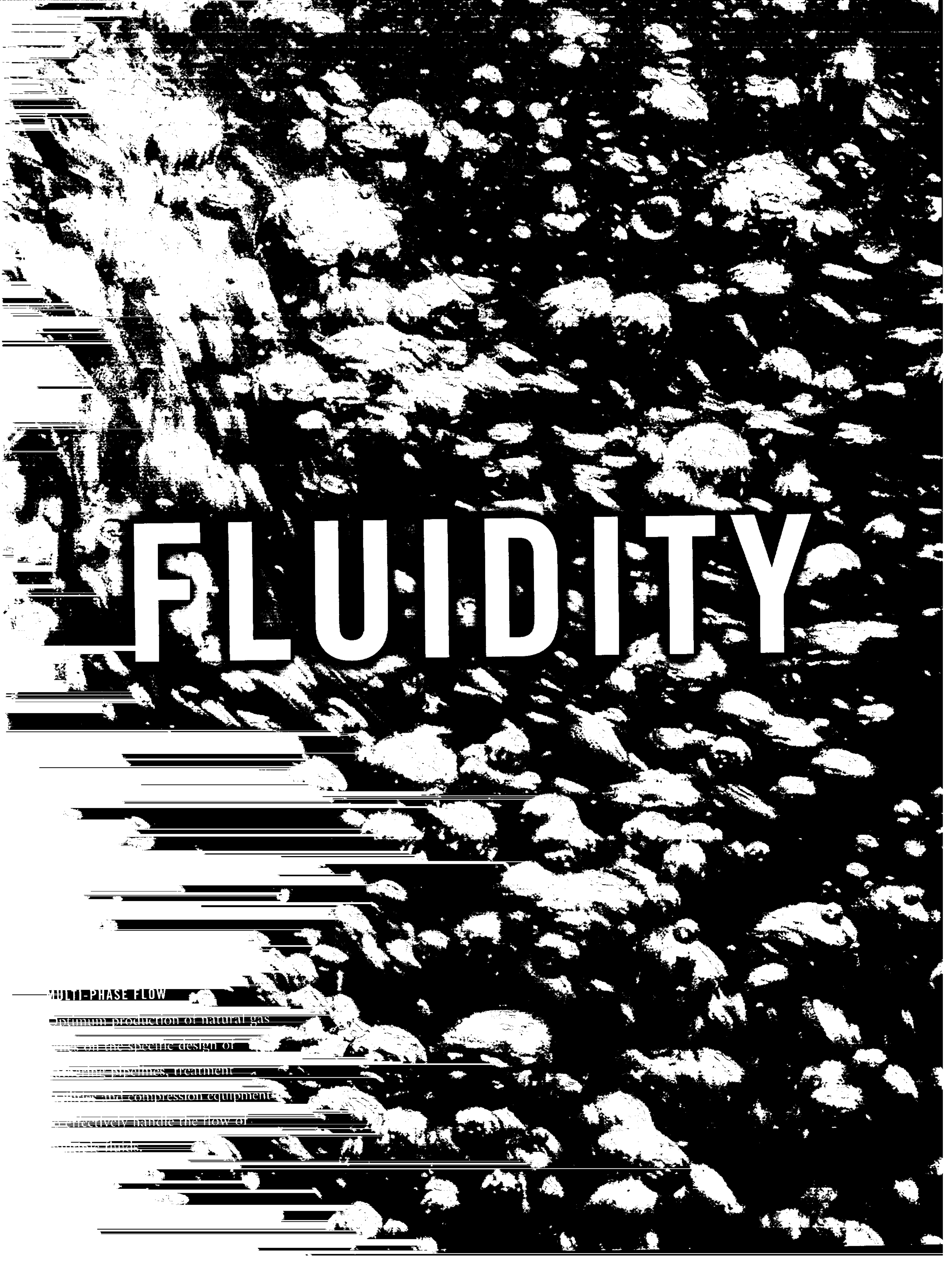
Development Highlights

In the University Block 9 Field, XTO continued to develop the Devonian formation at about 10,000 feet with infill wells. Since 1997, 65 new wells have been drilled of which about 30 are horizontal sidetracks. Along with identifying behind-pipe potential in the Wolfcamp and Pennsylvanian zones, the program has led to a new discovery in the shallow Grayburg interval. These Grayburg wells should yield 100 MBO to 150 MBO each at about $3 per barrel in development costs.

The advantage of a senior management team with over 25 years together is the ability to smoothly adapt tough challenges into business opportunities.

In the Prentice Northeast Unit, the Company continued on a steady pace of drilling 10-acre infill wells. Since 1995, more than 100 wells have been drilled, each realizing average reserves of 70 MBO at a finding cost of about $6 per barrel.

In the Cornell Unit, our development program focused on drilling infill wells to the San Andres formation and also restimulating older wellbores with sand fracturing. New "gas-cap" wells are cumulatively producing about 1.5 MMcf per day and another 3.5 MMcf per day of capacity will be available in April 2003. More than four years of upside opportunities have been identified for future development.



FLUIDITY

MULTI-PHASE FLOW

Optimum production of natural gas …es on the specific design of …pipelines, treatment …and compression equipment …effectively handle the flow of …fluids.

ALASKA

In 1998, XTO Energy applied its expertise in secondary recovery operations to the Cook Inlet of Alaska with the acquisition of the Middle Ground Shoal Field. The prolific oil field was discovered in the 1960's and had already produced 120 million barrels of crude when our technical teams identified an opportunity. The existing waterflood had not effectively swept the field due to the complexity of the faulted reservoir. Therefore, for about $45 million, the Company purchased 12 million barrels of oil reserves but visualized a target of 24 million barrels to be gained by improved reservoir recovery techniques.

Seismic data was reprocessed to better interpret the field's structural definition. Then, the application of 3-D reservoir mapping and simulation allowed our geoscientists to identify trapped oil pockets within several thousand feet of the prolific Hemlock reservoir sands. Since our development plans were initiated in 2000, production has increased from 3,600 BOPD to more than 4,100 BOPD.

Development Highlights

Current activities have focused on exploiting the vertically-oriented West Flank of the field. To date, eight directionally drilled wells have penetrated the oil-bearing sands yielding average reserves per well of 750 MBO at a cost of $3 million to $5 million. Also, several wells have been converted into injectors to optimize the sweep efficiency of the waterflood pattern.

A horizontal well has also been completed in the East Flank of the field to access oil bypassed in the waterflood. In 2003, we plan three new wells that will continue the field development at a total cost of $12 million to $15 million.

Shallow decline, high margin properties generate substantial free cash flow to fund development in XTO's high growth areas.

HUGOTON ROYALTY TRUST AREA

Since inception in 1986, XTO has built substantial holdings in the great gas basins of the Mid-Continent regions. The Hugoton Field of Kansas and Oklahoma, the Anadarko Basin of western Oklahoma and the Green River Basin of Wyoming have provided a wealth of long-lived multi-pay properties. These assets continue to offer a stable production base with tremendous cash flow.

From this valuable Mid-Continent property base, the Company formed the Hugoton Royalty Trust (HGT-NYSE) in 1998 and sold a portion of the units to the public. On a monthly basis, net revenues are distributed to the owner base providing active participation in the Company's legacy properties. Importantly, we continue to be a majority owner in the trust and operate the underlying properties with the same detailed focus and talent as applied in our other districts.

Development Highlights

The Company drilled 18 wells in northern Oklahoma targeting the Mississippian Osage Trend in Major County and the Chester Formation in Woodward County. Plans for 2003 call for another 18 new wells. In the Hugoton Field, our operational team continues to utilize energized "foam-fracs" to restimulate Chase Group intervals in older producing wells and increase production at a low cost. Successful stimulation projects affected 33 wells during the year with another 35 candidates identified for 2003.

In Wyoming, the development drilling activities in the Fontenelle Field were delayed during 2002 due to extremely depressed Rocky Mountain gas prices. As economics allow, the prolific Frontier sandstones hold ample opportunity for XTO to continue its infill drilling program. The Company has drilled 91 wells to date with an additional 35 potential locations identified for future development. Total production from these Green River Basin properties is steady at about 27 MMcf per day. In 2003, five new wells are planned with reserve expectations set at 1.5 Bcfe per well with five stimulation workovers planned.

ENERGY

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2002

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

Aggregate market value of the Common Stock based on the closing price on the New York Stock Exchange as of June 28, 2002 (the last business day of its most recently completed second fiscal quarter), held by nonaffiliates of the Registrant on that date was approximately $2,377,000,000

Number of Shares of Common Stock outstanding as of March 19, 2003 – 169,424,779

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, 2003.

TABLE OF CONTENTS

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 primarily internally generated and will be supplemented by incremental acquisitions. Given expected significant property divestitures by major energy, merchant energy, power generating and utility companies, larger strategic acquisitions could be made during the next year.

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 East Texas Basin;
- the Arkoma Basin of Arkansas and Oklahoma;
- the San Juan Basin of northwestern New Mexico and southwestern Colorado;
- 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 New Mexico;
- the Middle Ground Shoal Field of Alaska's Cook Inlet; and
- the Colquitt, Cotton Valley, Logansport and Oaks fields of northwestern Louisiana.

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, 2002 were 56.3 million Bbls of oil, 2.9 Tcf of natural gas and 25.4 million Bbls of natural gas liquids, based on December 31, 2002 prices of $29.69 per Bbl for oil, $4.41 per Mcf for gas and $17.86 per Bbl for natural gas liquids. Approximately 72% of December 31, 2002 proved reserves, computed on an Mcfe basis, were proved developed reserves. Increased proved reserves during 2002 were primarily the result of acquisitions and development and exploitation activities, partially offset by production. During 2002, our daily average production was 13,033 Bbls of oil, 513,925 Mcf of gas and 5,068 Bbls of natural gas liquids. Fourth quarter 2002 daily average production was 13,024 Bbls of oil, 551,356 Mcf of gas and 5,856 Bbls of natural gas liquids.

Our properties have relatively long reserve lives and highly predictable production profiles. Based on December 31, 2002 proved reserves and projected 2003 production, the average reserve-to-production index of our proved reserves is 14.6 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, 2002, we owned interests in 8,467 gross (4,506.6 net) wells, and we operated wells representing 93% 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 2,000 potential development drilling locations. Estimated net potential reserves associated with this inventory approach 2.9 Tcfe. Approximately one-third of these potential reserves are included in December 31, 2002 proved undeveloped reserves. Drilling plans are dependent upon product prices and the availability of drilling equipment.

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 East Texas, Louisiana, Colorado, Wyoming, the Arkoma Basin of Arkansas and Oklahoma, the Hugoton Field of Kansas and Oklahoma, and Major, Woods and Woodward counties, Oklahoma. We also operate gas processing plants in 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 operation.

We market our gas production and the gas output of our gathering and processing systems. A large portion of 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 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. The Board of Directors has authorized the purchase of up to two million, or 33%, of the outstanding units at a cost not to exceed $28.5 million. In June 1998, XTO and Cross Timbers Royalty Trust filed a registration statement with the Securities and Exchange Commission to register the Company's 1,360,000 units for sale in a public offering. The registration statement was filed in anticipation of improving commodity prices and related market conditions for oil and gas equities. The registration statement was amended in June 2001. Our sale of these units is dependent upon commodity prices and related market conditions for oil and gas.

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. 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 "General – 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,
- 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 return on development projects, and
- retaining management and technical staff that have substantial experience in the Company's 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,
- 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.

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 2,000 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 2003, 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 $20 million of our $400 million 2003 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 producing properties that we will not operate 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. 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 sell interests in additional royalty trusts in the future.

Business Goals. In December 2002, we announced our strategic goals for 2003 of increasing gas production by 15% over 2002 levels and increasing all production, including oil and natural gas liquids, by approximately 12% on an Mcfe basis. To achieve these growth targets, we plan to drill about 309 (255 net) development wells and perform approximately 385 (283 net) workovers and recompletions in 2003. Approximately 85% of these planned wells are classified as proved undeveloped reserves on our current reserve report.

We have budgeted $400 million for our 2003 drilling programs, which is expected to be funded by cash flow from operations. We plan to spend about 65% of the development budget in East Texas and about 20% in aggregate in the Arkoma and San Juan Basins, and the balance evenly allocated to Alaska, Permian Basin and Hugoton Royalty Trust properties. Exploration expenditures are expected to be approximately 5% of the 2003 budget. Costs of strategic property acquisitions during 2003 may reduce the amount currently budgeted for development and exploration. 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 these production and proved reserves 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

During 1998, we acquired producing properties for a total cost of $340 million. The East Texas Basin Acquisition was the largest of these acquisitions. The purchase closed in April 1998 at a price of $245 million, which was reduced to $215 million by a $30 million production payment sold to EEX Corporation. In September 1998, we acquired oil-producing properties in the Middle Ground Shoal Field of Alaska's Cook Inlet in exchange for 5.7 million shares of our common stock along with certain price guarantees and a non-interest bearing note payable of $6 million, resulting in a total purchase price of $45 million. We also acquired primarily gas-producing properties in northwest Oklahoma and the San Juan Basin of New Mexico for an estimated purchase price of $31 million. The 1998 acquisitions increased reserves by approximately 16.3 million Bbls of oil and 311.3 Bcf of gas.

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 March 2002, we acquired gas-producing properties for $20 million in the East Texas Freestone Trend. 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 coalbed 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 449,000 Bbls of oil, 330.4 Bcf of natural gas and 2.2 million Bbls of natural gas liquids. Approximately 10% of these reserves were proved undeveloped.

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, 2002:

(in thousands)	Proved Reserves Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)	Natural Gas Equivalents (Mcfe)	Discounted Present Value before Income Tax of Proved Reserves	
East Texas	4,799	1,518,593	2,793	1,564,145	$2,688,170	49.2%
Arkoma Basin	35	471,727	—	471,937	872,659	16.0%
San Juan Basin	1,614	536,132	22,640	681,656	867,613	15.9%
Hugoton Royalty Trust [a]	2,607	302,158	—	317,800	483,126	8.8%
Permian Basin	29,796	33,654	—	212,430	362,945	6.6%
Alaska Cook Inlet	15,869	—	—	95,214	136,708	2.5%
Cross Timbers Royalty Trust [b]	1,453	10,877	—	19,595	30,587	0.6%
Other	176	8,040	—	9,096	19,490	0.4%
Total	56,349	2,881,181	25,433	3,371,873	$5,461,298	100.0%

(a) Includes 1,784,000 Bbls of oil and 206,856,000 Mcf of gas and discounted present value before income tax of $330,746,000 related to our ownership of approximately 54% of Hugoton Royalty Trust units at December 31, 2002. The remainder is our retained interests in the properties underlying the trust's net profits interests.

(b) Includes 646,000 Bbls of oil and 7,089,000 Mcf of gas and discounted present value before income tax of $18,002,000 related to our ownership of approximately 23% of Cross Timbers Royalty Trust units at December 31, 2002. The remainder is our retained interests in the properties underlying the trust's net profits interests.

East Texas Area

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 with our 2002 acquisitions, we now have an interest in more than 186,000 gross (145,000 net) acres and a current development inventory of 800 to 1,000 wells with an estimated 2.2 Tcfe of reserve potential. We own an interest in 1,221 gross (1,094.4 net) wells which we operate and 139 gross (19.7 net) wells operated by others. We also own 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 2002, where 130 gross (108.2 net) gas wells were drilled and ten workovers were performed. 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. Currently transporting 225,000 Mcf per day, our gathering system was increased to more than 400,000 Mcf per day. We plan to continue our expansion efforts in this area by drilling approximately 144 wells in 2003.

Other East Texas Fields

Other fields in the East Texas area include Willow Springs, Opelika, Cotton Valley, Colquitt, Tri-Cities, Whelan, North Lansing and Logansport which provide opportunities for field extensions and infill drilling. In 2002, we drilled seven wells and performed 43 workovers in these fields. In 2003, we plan to drill five wells and perform 60 workovers. 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 2,500 Bbls of natural gas liquids per day, primarily from our own production in the surrounding wells.

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 918 gross (650.6 net) wells which we operate and 677 gross (122.4 net) wells operated by others. Of these wells, 150 gross (99.5 net) operated wells and 78 gross (15.1 net) nonoperated wells are dual completions. Our fault-block analysis technique has identified trapped hydrocarbons in offsetting and new reservoirs across the basin. During 2002, we drilled 54 wells and completed 136 workovers, 40 of which were stimulation/recompletions and 40 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 2002, the Orr and Hale sandstones were targets for our drilling in the Aetna, Silex and Cecil fields where 21 wells were drilled and 55 workovers were performed. Drilling was concentrated in the Aetna and Cecil fields where compression was also upgraded. In 2003, we plan to drill 31 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 2002, 160-acre well spacing was approved which added 30 to 40 potential well locations in the Booneville and Chismville fields. Reduced well spacing in the Gragg Field may occur in 2003. We drilled 19 wells in this area in 2002 and completed 74 workovers. In 2003, we plan to drill 13 wells.

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 14 wells were drilled and 7 workovers were performed in 2002. In 2003, there will be approximately ten wells drilled 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 570 gross (493.9 net) wells and have an interest in 142 gross (37.5 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 2002, we participated in the drilling of eight gross (5.5 net) wells in the northwestern portion of the county, targeting the Mississippian formation. We have budgeted six drill wells and 11 workovers in Major County for 2003. We were also very active in Woodward County, Oklahoma, where 10 gross (9.0 net) wells were drilled which targeted the Chester formation. In 2003, we plan to drill up to 12 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 19,500 Mcf per day, 70% of which is produced from Company-operated wells. Estimated capacity of the gathering system is 40,000 Mcf per day. Gas is delivered to a processing plant owned and operated by a third party, and then transmitted by a Company-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 the largest gas field in North America with an estimated five million productive acres. XTO owns an interest in 376 gross (353.0 net) wells that we operate and 80 gross (18.8 net) wells operated by others. During 2002, development of the Hugoton area included four successful recompletions to the Towanda formation. We also continued our restimulation program in the Chase intervals by completing 33 restimulations in 2002. We plan to perform 35 Chase restimulations during 2003.

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 185 gross (183.5 net) wells that we operate and 36 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. Development activities in the Fontenelle Field were delayed for most of 2002 by pipeline limitations and price volatility. During 2003, we plan to perform five workovers and may drill up to five wells in the Green River Basin.

San Juan Basin Area

The San Juan Basin of northwestern New Mexico and southwestern Colorado contains the second 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 coalbed methane operations into Colorado. We have now identified more than 400 potential drilling locations with approximately 350 Bcfe reserve potential. XTO owns an interest in 879 gross (716.3 net) wells that it operates and 830 gross (201.5 net) wells operated by others. Of these wells, 142 gross (124.8 net) operated wells and 129 gross (27.6 net) nonoperated wells are dual completions. In 2002, we participated in the drilling of 47 wells and completed 240 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 2003, we plan to drill 60 to 70 wells and perform 150 to 200 workovers and recompletions, including installation of as many as 40 wellhead compressors and 25 pumping units.

FRUITLAND COAL AND PICTURED CLIFFS FORMATIONS

XTO has centered its Fruitland Coal development efforts on trend extensions. Our coalbed 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 drilled one Fruitland Coal well in 2002 and plan to drill an additional 29 wells in 2003. A request to reduce current spacing of coalbed methane wells from 320 acres to 160 acres was approved by regulatory authorities in October 2002, adding more than 80 potential well locations.

MESAVERDE AND DAKOTA FORMATIONS

Eighty-acre spacing was approved 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. The reduced spacing will generate significant future development opportunities, and additional test wells are planned for 2003. In 2002, we drilled 28 Dakota and 18 Mesaverde wells. Thirty-one drill wells are planned for 2003.

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 79 gross (73.3 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 2002 focused on the Devonian, Grayburg & Wolfcamp formations. This field was one of our most active oil development areas during 2002 where XTO drilled seven wells, including four horizontal sidetrack wells. We also discovered a new shallow Grayburg producing interval. During 2003, we plan to drill up to 11 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. Tertiary recovery potential also exists through carbon dioxide flooding.

We operate the Prentice Northeast Unit, where we have a 91.6% working interest in 204 wells. We also own an interest in 81 gross (2.0 net) nonoperated wells. During 2002, we continued our 10-acre development drilling program by drilling eight gross (7.4 net) vertical wells in the Prentice Field. During 2003, we plan to continue our expansion of the potential infill area by drilling as many as eight 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 2002, we drilled three 10-acre infill oil wells and one gas cap well, and in 2003 we plan to drill three oil wells and three 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 120 million Bbls have been produced. 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.

In 2002, we completed an East Flank simulation study. One East Flank and three West Flank wells were drilled in 2002. Three additional East Flank wells are planned for 2003.

Reserves

The following are definitions of terms used in the following disclosures of oil and natural gas reserves:

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) 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, 2002, 2001 and 2000:

	December 31		
(in thousands)	2002	2001	2000
Proved developed			
Oil (Bbls)	47,178	41,231	46,334
Gas (Mcf)	2,042,661	1,452,222	1,328,953
Natural gas liquids (Bbls)	19,367	14,774	16,448
Mcfe	2,441,931	1,788,252	1,705,645
Proved undeveloped			
Oil (Bbls)	9,171	12,818	12,111
Gas (Mcf)	838,520	783,256	440,730
Natural gas liquids (Bbls)	6,066	5,525	5,564
Mcfe	929,942	893,314	546,780
Total proved			
Oil (Bbls)	56,349	54,049	58,445
Gas (Mcf)	2,881,181	2,235,478	1,769,683
Natural gas liquids (Bbls)	25,433	20,299	22,012
Mcfe	3,371,873	2,681,566	2,252,425
Estimated future net cash flows			
Before income tax	$10,528,450	$3,756,602	$15,239,560
After income tax	$ 7,384,215	$2,876,728	$10,291,946
Present value of estimated future net cash flows, discounted at 10%			
Before income tax	$ 5,461,298	$1,947,441	$ 7,748,632
After income tax	$ 3,873,585	$1,522,049	$ 5,262,030

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, 2002, 2001 and 2000. 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 2002 average realized prices used in the estimation of proved reserves were $29.69 per Bbl for oil, $4.41 per Mcf for gas and $17.86 per Bbl for natural gas liquids. See Note 15 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 2002 proved reserves are significantly higher than at year-end 2001 because of significantly lower product prices used in the estimation of year-end 2001 proved reserves. Year-end 2001 prices were $17.39 per Bbl for oil, $2.36 per Mcf for gas and $8.70 per Bbl for natural gas liquids.

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 2002, we filed estimates of oil and gas reserves as of December 31, 2001 with the U.S. Department of Energy on Form EIA-23. These estimates are consistent with the reserve data reported for the year ended December 31, 2001 in Note 15 to Consolidated Financial Statements, with the exception that Form EIA-23 includes only reserves from properties operated by the Company.

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, 2002, all of which are located in the United States:

	Operated Wells		Nonoperated Wells		Total[a]	
	Gross	Net	Gross	Net	Gross	Net
Oil	613	538.4	1,824	122.6	2,437	661.0
Gas	4,097	3,437.4	1,933	408.2	6,030	3,845.6
Total	4,710	3,975.8	3,757	530.8	8,467	4,506.6

(a) One gross (1.0 net) oil well and 518 gross (285.8 net) gas wells are dual completions.

Drilling Activity

The following table summarizes the number of wells drilled during the years indicated. As of December 31, 2002, we were in the process of drilling 54 gross (42.3 net) wells.

	Year Ended December 31					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Completed as –						
Oil wells	27	15.5	85	33.0	48	29.9
Gas wells	303	227.2	282	200.3	172	114.6
Non-productive	13	5.9	15	5.9	9	1.3
Total	343	248.6	382	239.2	229	145.8
Exploratory wells						
Completed as –						
Oil wells	—	—	1	0.5	4	2.8
Gas wells	—	—	4	2.3	1	0.5
Non-productive	3	1.5	2	1.8	1	0.5
Total	3	1.5	7	4.6	6	3.8
Total[a]	346	250.1	389	243.8	235	149.6

(a) Included in totals are 75 gross (11.2 net) wells in 2002, 125 gross (16.5 net) wells in 2001 and 66 gross (8.5 net) wells in 2000 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, 2002. Excluded from this summary is acreage related to royalty, overriding royalty and other similar interests.

	Developed Acres[a][b]		Undeveloped Acres	
	Gross	Net	Gross	Net
Arkansas	519,538	226,413	26,619	19,433
Oklahoma	464,406	325,194	15,126	7,149
Texas	324,642	210,739	49,390	36,536
New Mexico	255,858	170,630	1,520	1,531
Kansas	66,670	58,169	—	—
Louisiana	53,202	26,554	—	—
Wyoming	45,007	30,241	572	315
Colorado	28,651	16,282	—	—
Other	23,803	11,595	509	955
Total	1,781,777	1,075,817	93,736	65,919

(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 quantities produced for the indicated period:

	Year Ended December 31		
	2002	2001	2000
Sales prices			
Oil (per Bbl)	$24.24	$23.49	$27.07
Gas (per Mcf)	$ 3.49	$ 4.51	$ 3.38
Natural gas liquids (per Bbl)	$14.31	$15.41	$19.61
Production expense per Mcfe	$ 0.57	$ 0.57	$ 0.53
Taxes, transportation and other expense per Mcfe	$ 0.25	$ 0.33	$ 0.35

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.

As partial consideration for an acquisition, we agreed to sell gas volumes of 35,000 Mcf per day in 2003 at specified discounts from index prices. Delivery of 20,000 Mcf per day of these volumes is from the San Juan Basin, with the remainder from the East Texas Basin.

As part of an acquisition, we assumed a commitment to sell 6,800 Mcf of gas per day in Arkansas through April 2003 at prices which are adjusted by the monthly index price. The prices ranged from $0.46 to $0.72 per Mcf in 2002.

The Company's production and reserves are adequate to meet the above sales 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 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, "General – Product Prices."

Federal and State Regulations

There have been, and continue to be, 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 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 ("FERC"). 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 867 employees as of December 31, 2002. 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, 54, 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, 52, 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, 53, 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, 44, 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, 48, 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, 52, 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 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 allege 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 allege that these actions reduced the royalties paid to the plaintiffs and those similarly situated, and that such actions are a breach of the leases under which the royalties are paid. These deductions allegedly include production and post-production costs, marketing costs, administration costs and costs incurred by us in gathering, compressing, dehydrating, processing, treating, blending and/or transporting the gas produced. We contend that, to the extent any fees are proportionately borne by the plaintiffs, these fees are established by arm's-length negotiations with third parties or, if charged by affiliates, are comparable to fees charged by third party gatherers or processors. We further contend that any such fees enhance the value of the gas or the products derived from the gas. The parties have signed a settlement agreement under which we will pay $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, is $2.1 million, which has been accrued in our financial statements. The court has tentatively approved the settlement, subject to a fairness hearing in April 2003.

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. According to the U.S. Department of Justice, the plaintiff has made similar allegations in over 70 actions filed against more than 300 other companies. 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 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. We have reached a tentative settlement with the Department of Interior to pay $288,000 in settlement of all claims. The settlement should be finalized in second quarter 2003. Management's estimate of the potential liability from this claim 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 and one of our subsidiaries were dismissed from the suit and another subsidiary was added. A hearing on whether to certify the case as a class action was held in January 2003, and the decision of the court is pending. 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.

We are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Company 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 2002.

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 2002 and 2001 (as adjusted for the four-for-three stock split effected on March 18, 2003 and the three-for-two stock split effected on June 5, 2001):

	High	Low	Dividend
2002			
First Quarter	$15.188	$11.018	$0.0075
Second Quarter	16.163	13.763	0.0075
Third Quarter	15.743	11.513	0.0075
Fourth Quarter	19.793	15.090	0.0075
2001			
First Quarter	$15.475	$ 9.407	$0.0050
Second Quarter	16.300	10.313	0.0075
Third Quarter	12.375	9.225	0.0075
Fourth Quarter	14.475	9.938	0.0075

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. Our revolving credit agreement with banks restricts the amount of dividends to 25% of cash flow from operations, as defined, for the latest four consecutive quarterly periods. The Company's 7½% senior notes and 8¾% senior subordinated notes also place certain restrictions on distributions to common stockholders, including dividend payments.

On February 18, 2003, the Board of Directors declared a quarterly dividend of $0.01 per share payable on April 15, 2003 to stockholders of record on March 31, 2003. Because of the four-for-three stock split effected on March 18, 2003, this represents a 33% increase in the dividend rate. On March 19, 2003, we had approximately 683 stockholders of record.

Item 6. Selected Financial Data

The following table shows selected financial information for the five years ended December 31, 2002. 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 four-for-three stock split effected March 18, 2003 and the three-for-two stock splits effected in February 1998, 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)	2002	2001	2000	1999	1998
CONSOLIDATED INCOME STATEMENT DATA					
Revenues					
Oil and condensate	$ 115,324	$ 116,939	$ 128,194	$ 86,604	$ 56,164
Gas and natural gas liquids	681,147	710,348	456,814	239,056	182,587
Gas gathering, processing and marketing	11,622	12,832	16,123	10,644	9,438
Other	2,070	(1,371)	(280)	4,991	1,297
Total Revenues	$ 810,163	$ 838,748	$ 600,851	$ 341,295	$ 249,486
Earnings (loss) available to common stock	$ 186,059[a]	$ 248,816[b]	$ 115,235[c]	$ 44,964[d]	$ (71,498)[e]
Per common share					
Basic	$ 1.12	$ 1.52[f]	$ 0.81	$ 0.32	$ (0.55)
Diluted	$ 1.10	$ 1.50[f]	$ 0.77	$ 0.32	$ (0.55)
Weighted average common shares outstanding	166,700	163,340	142,307	140,455	130,187
Dividends declared per common share	$ 0.0300	$ 0.0275	$ 0.0167	$ 0.0133	$ 0.0533
CONSOLIDATED STATEMENT OF CASH FLOWS DATA					
Cash provided (used) by					
Operating activities	$ 490,842	$ 542,615	$ 377,421	$ 133,301	$ (53,876)
Investing activities	$ (736,817)	$ (610,923)	$ (133,884)	$ (156,370)	$ (376,564)
Financing activities	$ 254,119	$ 67,680	$ (241,833)	$ 16,470	$ 438,957
CONSOLIDATED BALANCE SHEET DATA					
Property and equipment, net	$2,370,965	$1,841,387	$1,357,374	$1,339,080	$1,050,422
Total assets	$2,648,193	$2,132,327	$1,591,904	$1,477,081	$1,207,005
Long-term debt	$1,118,170	$ 856,000	$ 769,000	$ 991,100	$ 920,411
Stockholders' equity	$ 907,786	$ 821,050	$ 497,367	$ 277,817	$ 201,474
OPERATING DATA					
Average daily production					
Oil (Bbls)	13,033	13,637	12,941	14,006	12,598
Gas (Mcf)	513,925	416,927	343,871	288,000	229,717
Natural gas liquids (Bbls)	5,068	4,385	4,430	3,631	3,347
Mcfe	622,532	525,062	448,098	393,826	325,390
Average sales price					
Oil (per Bbl)	$ 24.24	$ 23.49	$ 27.07	$ 16.94	$ 12.21
Gas (per Mcf)	$ 3.49	$ 4.51	$ 3.38	$ 2.13	$ 2.07
Natural gas liquids (per Bbl)	$ 14.31	$ 15.41	$ 19.61	$ 11.80	$ 7.62
Production expense (per Mcfe)	$ 0.57	$ 0.57	$ 0.53	$ 0.53	$ 0.53
Taxes, transportation and other expense (per Mcfe)	$ 0.25	$ 0.33	$ 0.35	$ 0.23	$ 0.25
Proved reserves					
Oil (Bbls)	56,349	54,049	58,445	61,603	54,510
Gas (Mcf)	2,881,181	2,235,478	1,769,683	1,545,623	1,209,224
Natural gas liquids (Bbls)	25,433	20,299	22,012	17,902	17,174
Mcfe	3,371,873	2,681,566	2,252,425	2,022,653	1,639,328
OTHER DATA					
Operating cash flow [g]	$ 515,904	$ 549,567	$ 344,638	$ 132,683	$ 78,480
Ratio of earnings to fixed charges [h]	5.6	7.7	2.8	1.9	— [i]

(a) 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.
(b) 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.
(c) 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.
(d) Includes pre-tax effect of a $40.6 million gain on sale of Hugoton Royalty Trust units.
(e) Includes pre-tax effects of a $93.7 million net loss on investment in equity securities and a $2 million, non-cash impairment charge.
(f) Before cumulative effect of accounting change, earnings per share were $1.79 basic and $1.77 diluted.
(g) Defined as cash provided by operating activities before changes in operating assets and liabilities and exploration expense. Because of exclusion of changes in operating assets and liabilities and exploration expense, this cash flow statistic is different from cash provided (used) by operating activities, as is disclosed under generally accepted accounting principles and reconciled to operating cash flow as follows:

	2002	2001	2000	1999	1998
Cash provided (used) by operating activities	$490,842	$542,615	$377,421	$133,301	$ (53,876)
Changes in operating assets and liabilities	22,876	1,514	(33,830)	(1,522)	124,322
Exploration expense	2,186	5,438	1,047	904	8,034
Operating cash flow	$515,904	$549,567	$344,638	$132,683	$ 78,480

We believe operating cash flow is a better liquidity indicator for oil and gas producers because of the adjustments made to cash provided (used) by operating activities, explained as follows:
- Adjustment for changes in operating assets and liabilities eliminates fluctuations related to the timing of cash receipts and disbursements, which can vary from period-to-period because of conditions we cannot control (for example, the day of the week on which the last day of the period falls), and results in attributing cash flow to operations of the period that provided (used) the cash flow.
- Adjustment for exploration expense is to provide an amount comparable to operating cash flow for full cost companies and to eliminate the effect of a discretionary expenditure that is part of our capital budget.

(h) For purposes of calculating this ratio, earnings are before income tax and fixed charges. Fixed charges include interest costs, the portion of rentals considered to be representative of the interest factor and preferred stock dividends.
(i) Fixed charges exceeded earnings by $108.4 million. Excluding the effect of items in (e) above, fixed charges exceeded earnings by $19 million.

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). 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.

General

The events described below affect the comparability of results of operations and financial condition for the years ended December 31, 2002, 2001 and 2000, and may impact future operations and financial condition.

Stock Splits. We effected three-for-two stock splits on September 18, 2000 and June 5, 2001 and a four-for-three stock split on March 18, 2003. All common stock shares, treasury stock shares and per share amounts have been retroactively restated to reflect all stock splits.

2002 Acquisitions. During 2002, we acquired gas-producing properties at a total cost of $358.1 million funded by a combination of bank borrowings, proceeds from the Company's sale of senior notes and operating cash flow. The acquisitions include:

- *Freestone Trend Acquisition.* In March 2002, we acquired gas-producing properties in the East Texas Freestone Trend for $20 million.
- *Marathon East Texas Acquisition.* In May 2002, we acquired gas-producing properties in East Texas and Louisiana from Marathon Oil Company through an exchange of properties in the Powder River Basin of Wyoming that were acquired from CMS Oil and Gas Company in May 2002 for $101 million.

- *Marathon San Juan Basin Acquisition.* In July 2002, we acquired gas-producing properties in the San Juan Basin of New Mexico for $43 million from Marathon Oil Company.
- *Huber Acquisition.* In December 2002, we acquired coalbed methane gas-producing properties in the San Juan Basin of Colorado for $153.8 million from J.M. Huber Corporation.

2001 Acquisitions. During 2001, we acquired predominantly gas-producing properties at a total cost of $242 million primarily funded by bank borrowings and operating cash flow. The acquisitions include:

- *Herd Acquisition.* In January 2001, we acquired gas properties in East Texas and Louisiana for $115 million from Herd Producing Company, Inc.
- *Miller Acquisition.* In February 2001, we acquired gas properties in East Texas for $45 million from Miller Energy, Inc. and other owners.

Hugoton Royalty Trust Sales. We created Hugoton Royalty Trust in December 1998 by conveying 80% net profits interests in producing properties in Kansas, Oklahoma and Wyoming. In April and May 1999, we sold 17 million units, or 42.5%, of Hugoton Royalty Trust in its initial public offering. Total proceeds from this sale were $148.6 million, which were used to reduce bank debt. Total gain on sale, including the sale of units pursuant to an employee incentive plan, was $40.6 million before income tax. In October and November 2000, we sold 1.2 million units, or approximately 3%, of Hugoton Royalty Trust pursuant to an employee incentive plan at a total gain of $11 million before income tax.

2000 Property Sales. In March 2000, we sold oil- and gas-producing properties in Crockett County, Texas and Lea County, New Mexico for total gross proceeds of $68.3 million.

2002, 2001 and 2000 Development and Exploration Programs. Gas development focused on the East Texas area and the Arkoma and San Juan basins during 2002 and 2001, and on the East Texas area and Fontenelle Unit during 2000. Oil development was concentrated in Alaska during 2002 and 2001 and in the University Block 9 Field during all three years. Exploration activity has been primarily geological and geophysical analysis, including seismic studies, of undeveloped properties. Exploratory expenditures were $2.2 million in 2002, $5.4 million in 2001 and $1 million in 2000. Exploration expense for 2001 includes dry hole expense of $2.2 million.

2003 Development and Exploration Program. We have budgeted $400 million for our 2003 development and exploration program, which is expected to be funded primarily by cash flow from operations. We anticipate exploration expenditures will be approximately 5% of the 2003 budget. The cost of any property acquisitions during 2003 may reduce the amount currently budgeted for development and exploration. The total capital budget, including acquisitions, will be adjusted throughout 2003 to focus on opportunities offering the highest rates of return.

Common Stock Transactions. In November 2000, we sold 13.2 million shares of common stock from treasury with net proceeds of approximately $126.1 million. The proceeds were used to reduce bank debt.

Treasury Stock Purchases. We periodically repurchase shares of our common stock as part of our strategic acquisition plans. We purchased on the open market 10.5 million shares at a cost of $41.4 million in 2000. As of March 20, 2003, 8.6 million shares remain under the May 2000 Board of Directors' authorization to purchase an additional 9 million shares.

Conversion of Preferred Stock. In 2000 and 2001, all outstanding preferred stock was converted into 7.4 million shares of common stock.

Investment in Equity Securities. In 1998, we purchased what we believed to be undervalued oil and gas reserves by acquiring common stock of publicly traded independent oil and gas producers at a total cost of $167.7 million. For accounting purposes, we considered equity securities purchased in 1998 to be trading securities since they were purchased with the intent to resell in the near future, and therefore recognized unrealized investment gains and losses in the income statements. After selling a portion of these securities in 1998 and 1999, we sold our remaining investment in equity securities in 2000 for $43.7 million. We recognized a gain of $13.3 million in 2000 related to this investment.

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 provided by predictable, stable cash flow.

During 2002, all 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. During 2000, hedging activities reduced gas revenue by $40.5 million and reduced oil revenue by $7.8 million.

The following summarizes our April 2003 through December 2004 natural gas and crude oil NYMEX hedging positions at March 20, 2003, excluding basis adjustments which have been separately hedged. Prices to be realized for hedged production may be less than these NYMEX prices because of location, quality and other adjustments. See Note 8 to the Consolidated Financial Statements.

NATURAL GAS	Futures and Physical Contracts		Collars			
				NYMEX Price		
Production Period	Mcf per Day	Average NYMEX Price	MCF per Day	Ceiling	Floor	Total Hedged Mcf per Day
April - June 2003	450,000	$3.97	50,000	$5.57	$4.50	500,000
July - December 2003	400,000	$3.99	50,000	$5.57	$4.50	450,000
January - December 2004	150,000	$4.15	—	—	—	150,000

CRUDE OIL	Three-Way Collars			
		Average NYMEX WTI Price		
Production Period	Bbls per Day	Ceiling	Provisional Floor (a)	Strike (a)
April - June 2003	2,000	$33.90	$30.55	$24.15
July - September 2003	2,000	$31.38	$28.03	$21.63
October - December 2003	2,000	$29.97	$26.62	$20.22

(a) *At market prices within the range of the provisional floor and strike price, we will receive payment from the counterparty to effectively receive the provisional floor price. At market prices below the strike price, we will receive the market price plus $6.40, the spread between the provisional floor and strike price.*

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. Realized and unrealized non-hedge derivative gains and losses are recorded in our income statements. We recorded a $2.6 million gain in 2002, a $54.4 million gain in 2001 and a $55.8 million loss in 2000 related to changes in fair value of non-hedge derivatives. The 2000 loss and $29.5 million of the 2001 gain are 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 cash flow hedges are recorded in accumulated other comprehensive income. At December 31, 2002, we have a net unrealized loss of $61.6 million (net of $33.1 million tax) in accumulated other comprehensive income related to the fair value of derivatives designated as cash flow hedges. The ultimate settlement value of these hedges will be recognized in the income statement as oil and gas revenue when the related production occurs through 2003 and 2004.

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. See Note 7 to Consolidated Financial Statements.

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. As a result of these transactions, we recorded a total pre-tax loss on extinguishment of debt of $8.5 million, which includes the effects of redemption premium paid and expensing related deferred debt costs. We reported this loss as non-extraordinary in accordance with early adoption provisions of SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections,* related to rescission of SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt.*

Incentive Compensation. Incentive compensation generally results from awards of performance shares, royalty trust options and stock appreciation rights, and subsequent changes in our stock price. Incentive compensation totaled $27 million in 2002, $9.6 million in 2001 and $26.1 million in 2000, which was primarily related to performance share grants, as well as royalty trust option exercises in 2000. As of December 31, 2002, there were 200,000 performance shares outstanding that vest when the common stock price reaches $20.00, 104,000 performance shares outstanding that vest when the common stock price reaches $20.63 and 9,000 performance shares that vest in 2003.

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.

- *Oil.* Crude oil prices are generally determined by global supply and demand. Despite OPEC production increases in 2000, increased demand sustained higher prices. The West Texas Intermediate ("WTI") posted price reached $34.25 per Bbl in September 2000, then its highest level in ten years. Lagging demand, attributable to a worldwide economic slowdown, caused oil prices to decline during the remainder of 2001. OPEC members agreed to cut daily production by one million barrels in April 2001 and an additional one million barrels in September 2001 to adjust for weak demand and excess supply. The economic decline was accelerated by the terrorist attacks in the United States on September 11, 2001, placing further downward pressure on oil prices. OPEC cut an additional 1.5 million barrels per day for 2002. Oil prices increased during 2002 because of OPEC production discipline and rising uncertainty surrounding the Middle East. OPEC members agreed to increase daily oil production 1.5 million barrels beginning February 1, 2003, to help stabilize a volatile world market. With the war in Iraq, however, oil prices are expected to remain volatile. We use commodity price hedging instruments to reduce our exposure to oil price fluctuations. Excluding the effect of these hedging instruments, our average oil price was $24.52 in 2002 and $28.72 in 2000. We did not hedge oil prices in 2001 and our average oil price was $23.49. At March 14, 2003, the average NYMEX oil price for the following 12 months was $30.15 per Bbl. For first quarter 2003, we have hedged 6,000 Bbls per day of crude oil production at an average NYMEX price of $25.58 per Bbl. Excluding these hedged volumes, we estimate that a $1.00 per barrel increase or decrease in the average oil sales price would result in approximately a $4 million change in 2003 annual operating cash flow.

- *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. At the beginning of 2000, NYMEX gas prices approximated $2.30 per MMBtu. Gas prices strengthened in 2000, reaching a record high of $10.10 per MMBtu in December 2000 as winter demand strained gas supplies. Gas prices declined during 2001 because of fuel switching due to higher prices, milder weather and a weaker economy, which reduced the demand for gas to generate electricity and resulted in increased gas storage levels. As of December 31, 2001, the NYMEX gas price was $2.57 per MMBtu. Despite the winter of 2001-2002 being one of the warmest on record and resulting higher than average storage levels, gas prices increased during 2002 as a result of low levels of drilling activity, increased industrial demand, colder weather and international instability. At March 14, 2003, the average NYMEX gas price for the following 12 months was $5.37 per MMBtu. We use commodity price hedging instruments, including fixed price physical delivery contracts, to reduce our exposure to gas price fluctuations. Excluding the effect of these hedging instruments, our average gas price was $2.98 in 2002, $3.87 in 2001 and $3.70 in 2000. We have hedges in place on approximately 80% of expected 2003 gas production with an average NYMEX price of $3.98. We have also hedged 150,000 Mcf per day of natural gas production for 2004 at an average NYMEX price of $4.15 per Mcf. Excluding these hedged volumes, we estimate that a $0.10 per Mcf increase or decrease in the average gas sales price would result in a $3.9 million change in 2003 annual operating cash flow.

Impairment Provision. We evaluate possible impairment of producing properties when conditions indicate they may be impaired. 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.

Results of Operations

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 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 settlement with Enron and a $1.7 million after-tax derivative 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. 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 "General – Product Prices – Oil" above). Decreased production is the result of natural decline, partially offset by development.

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 "General – 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.

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. See Note 7 to Consolidated Financial Statements.

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 acquisitions and development and related increased production.

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 includes dryhole costs of $2.2 million.

Taxes, transportation and other deductions decreased 10%, or $6.4 million, primarily because of lower product revenues, 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.

Depreciation, depletion and amortization ("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 increased incentive compensation of $17.4 million 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. These contracts terminated in 2001. See Note 6 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.

2001 Compared to 2000

For the year 2001, earnings available to common stock were $248.8 million compared with earnings of $115.2 million for 2000. Earnings for 2001 include a $44.6 million after-tax charge for adoption of the new 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. The 2000 earnings include a $7.3 million after-tax gain from the sale of Hugoton Royalty Trust units, a $13.1 million after-tax gain on sale of properties, an $8.8 million after-tax gain on investment in equity securities, a $17.3 million after-tax charge for incentive compensation and a $36.8 million after-tax derivative fair value loss.

Revenues for 2001 were $838.7 million, or 40% above 2000 revenues of $600.9 million. Oil revenue decreased $11.3 million, or 9%, because of a 13% decrease in oil prices from an average of $27.07 per Bbl in 2000 to $23.49 in 2001 (see "General – Product Prices – Oil" above), partially offset by a 5% increase in oil production. Increased production was primarily because of the 2001 development program.

Gas and natural gas liquids revenue increased $253.5 million, or 56%, because of a 21% increase in gas production and a 33% increase in gas prices from an average of $3.38 per Mcf in 2000 to $4.51 in 2001 (see "General – Product Prices – Gas" above). These increases were partially offset by a 1% decrease in natural gas liquids production and a 21% decrease in natural gas liquids prices from an average price of $19.61 per Bbl in 2000 to $15.41 in 2001. Increased gas production was attributable to the 2001 development program. Decreased gas liquids production was primarily because higher gas prices in first quarter 2001 made ethane extraction uneconomical at some gas plants.

Gas gathering, processing and marketing revenues decreased $3.3 million primarily because of decreased processing margins. Other revenues declined $1.1 million primarily because of decreased gains on sale of properties.

Expenses for 2001 totaled $327.8 million as compared with total 2000 expenses of $388.7 million. Excluding derivative fair value (gain) loss, expenses for 2001 totaled $382.2 million, or 15% above total expenses of $332.9 million for 2000. Most expenses increased in 2001 because of acquisitions and development and related increased production.

Production expense increased $23 million, or 26%, because of increased production, as well as higher maintenance, overhead, fuel, pumper and workover expense. Production expense per Mcfe increased $0.04. Our 2001 exploration expense was $5.4 million compared with $1 million for 2000 because of dry hole costs of $2.2 million and increased geological and geophysical costs.

Taxes, transportation and other deductions increased 12%, or $7 million, primarily because of increased oil and gas revenues. Taxes, transportation and other per Mcfe decreased 6% from $0.35 to $0.33 primarily because of lower severance tax rates on certain new wells in East Texas.

DD&A increased $24.5 million, or 19%, primarily because of increased production and higher acquisition and drilling costs. On an Mcfe basis, DD&A increased slightly from $0.79 in 2000 to $0.81 in 2001.

General and administrative expense decreased $10.2 million, or 21%, because of decreased incentive compensation of $16.5 million which was partially offset by increased expenses from Company growth. Excluding incentive compensation, general and administrative expense per Mcfe increased from $0.14 in 2000 to $0.15 in 2001.

The derivative fair value gain of $54.4 million in 2001 primarily reflects the effect of decreased natural gas prices during the year on the fair value of outstanding call options and a gas physical delivery contract with crude oil-based pricing. The derivative fair value loss of $55.8 million in 2000 reflects the effect of increased prices during the period on the fair value of call options. These derivatives do not qualify for hedge accounting. See Note 6 to Consolidated Financial Statements.

Interest expense decreased $23.3 million, or 30%, primarily because of a 19% decrease in the weighted average interest rate, an 11% decrease in weighted average borrowings and increased capitalized interest. Interest expense per Mcfe decreased 40% from $0.48 in 2000 to $0.29 in 2001.

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 2003.

Cash provided by operating activities was $490.8 million in 2002, compared with cash provided by operating activities of $542.6 million in 2001 and $377.4 million in 2000. Decreased operating cash flow from 2001 to 2002 was primarily because of decreased prices, while increased operating cash flow from 2000 to 2001 was primarily because of increased prices and production from acquisitions and development activity. Before changes in operating assets and liabilities and exploration expense, cash flow from operations was $515.9 million in 2002, $549.6 million in 2001 and $344.6 million in 2000. Cash flow from operations is largely dependent upon the prices received for oil and gas production. We have hedged approximately 80% of our projected 2003 gas production. See "Product Prices" under "General" 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 24% from $2.1 billion at December 31, 2001 to $2.6 billion at December 31, 2002, primarily because of Company growth related to acquisitions and development. As of December 31, 2002, total capitalization was $2 billion, of which 55% was long-term debt. Capitalization at December 31, 2001 was $1.7 billion of which 51% was long-term debt. The increase in the debt-to-capitalization ratio from year-end 2001 to 2002 is primarily because of a change in accumulated other comprehensive income, a component of stockholders' equity, from a gain to a loss position related to the effect of higher gas prices on hedge derivatives.

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. The decrease from working capital of $37.5 million at December 31, 2001 to negative working capital of $41.1 million at December 31, 2002 was primarily attributable to the change in derivative fair value assets and liabilities, net of the related tax effects. Any cash settlement of hedge derivatives should 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 which 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. Because of significant payments to counterparties in 2003, we have made draws on our bank debt, reducing our unused borrowing capacity to a low of $120 million in March 2003. We will repay these borrowings upon receipt of payment for our production.

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 security are obtained as considered necessary to limit risk of loss.

Financing

On December 31, 2002, borrowings under the revolving credit agreement with commercial banks were $605 million with unused borrowing capacity of $195 million. The interest rate of 2.84% at December 31, 2002 is based on the one-month London Interbank Offered Rate plus 1.375%. Based on the value of our reserves, the borrowing base is $1.2 billion effective June 30, 2002, and the total bank commitment is $800 million. The borrowing base is redetermined annually based on the value and expected cash flow of our proved oil and gas reserves. If, at any time, senior debt exceeds the borrowing base then in effect, the banks may require that the excess be repaid within a year. Based on reserve values at December 31, 2002 and using parameters specified by the banks, we propose to increase the borrowing base to $1.8 billion. Assuming approval by the banks, this increase would be effective June 30, 2003. Borrowings under the loan agreement are due May 12, 2005, but may be prepaid at any time without penalty. We may renegotiate the loan agreement to increase borrowing capacity and extend the revolving facility.

Our Standard & Poors corporate credit rating is BB+ 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 October 2001, 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 securities, preferred stock or common stock. The total price of securities that can be offered is $600 million, 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. After we sold $350 million of 7½% senior notes in April 2002, $250 million remains available for future offerings under the shelf registration statement. See Note 3 to Consolidated Financial Statements.

Capital Expenditures

In 2002, exploration and development cash expenditures totaled $372.7 million compared with $386.5 million in 2001. We have budgeted $400 million for the 2003 development and exploration program. As we have done historically, we expect to fund the 2003 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.

We plan to fund any future property acquisitions through a combination of cash flow from operations and proceeds from asset sales, bank debt, public equity or debt transactions. 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.

In 2000, the Board of Directors authorized the repurchase of a total of 16.5 million shares of our common stock. During 2000, we repurchased 10.5 million shares of our common stock at a cost of $41.4 million, including 2.6 million shares repurchased under a 1998 Board authorization. No shares were repurchased in 2001 or 2002. As of March 20, 2003, 8.6 million shares are available for repurchase.

To date, we have not spent significant amounts to comply with environmental or safety regulations, and we do not expect to do so during 2003. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Dividends

The Board of Directors declared quarterly dividends of $0.0033 per common share for the first and second quarter 2000, $0.0050 per common share for each quarter from the third quarter 2000 through first quarter 2001 and $0.0075 per common share each quarter for the remainder of 2001 and 2002. In February 2003, the Board of Directors declared a first quarter 2003 dividend of $0.01 per common share. Our ability to pay dividends is dependent upon available cash flow, as well as other factors. In addition, our debt agreements restrict the amount of common stock dividends and treasury stock repurchases to 25% of cash flow from operations, as defined, for the last four quarters.

Contractual Obligations and Commitments

The following summarizes our significant obligations and commitments to make future contractual payments as of December 31, 2002. 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.

Long-Term Debt. Borrowings under our senior bank revolving credit facility were $605 million at December 31, 2002. Bank debt is not due until May 2005, but may be prepaid at any date. We may renegotiate our bank debt to increase borrowing capacity and extend its maturity. At December 31, 2002, senior notes due in April 2012 totaled $350 million and senior subordinated notes due in November 2009 totaled $163.2 million. Subordinated debt may currently be redeemed at a price of approximately 104% of par. For further information regarding long-term debt, see Note 3 to Consolidated Financial Statements.

Operating Leases. Our minimum lease payment commitments under noncancelable lease agreements totaled $91.8 million at December 31, 2002. Estimated annual payments under these lease agreements for the next five years are disclosed in Note 5 to Consolidated Financial Statements. Estimated annual payments total $16.7 million for 2003 and decline for subsequent years.

Guarantees. Under the terms of some of our operating leases, 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, 2002, we estimate the total contingent payable under these guarantees does not exceed $5 million.

Drilling Contracts. We have drilling rig commitments of $42.5 million in 2003. Early termination of these contracts would require a termination fee of $7.5 million in lieu of these commitments. These costs are part of our budgeted capital expenditures of $400 million for 2003.

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, 2002, market prices generally exceeded the fixed prices specified by these contracts, resulting in a net derivative fair value loss at December 31, 2002 of $109.3 million, of which $87.4 million relates to contracts settling in 2003 and $21.9 million relates to contracts settling in 2004 through 2006. 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 6 to Consolidated Financial Statements.

Post-Retirement Plans

We have a retiree medical plan that provides retirees (age 55 through 64 with at least five years of service) with health care benefits similar to those provided employees. 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. 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. A company, partially owned by one of our directors, performed consulting services in connection with our acquisition of properties in East Texas, Louisiana and the San Juan Basin of New Mexico during 2002. 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. This director-related company received consulting fees of $994,000 in 2000 for consulting services performed in connection with our acquisition and divestiture programs.

In 1998, this same director-related company performed consulting services in connection with a producing property 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. We acquired this potential interest from the director-related company and other parties in 2001 for a price of $15 million, pursuant to an independent 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, 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 must be expensed through an impairment provision if in excess of the estimated future cash flows of proved reserves. We evaluate possible impairment of producing properties 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 using discounted estimated future after-tax cash flows based on current market prices. This 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.

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 15 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.

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 "General – 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 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. During 2000, we recorded a significant loss related to the fair value of call options. 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 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 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 Changes

Effective January 1, 2003, we have adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires that the fair value of the liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate can be made. 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 the offsetting charge to property cost. Periodic accretion of discount of the estimated liability is recorded 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 and depreciation. 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.

We have used an expected cash flow approach to estimate our asset retirement obligation under SFAS No. 143. As of the January 1, 2003 adoption date, we estimate a retirement obligation of $75 million, an increase in property cost of $61 million, a reduction of accumulated depreciation, depletion and amortization of $17 million and a cumulative effect of accounting change gain, net of tax, of $2 million. As a result of adoption of SFAS No. 143, we estimate that in 2003 accretion of discount expense will be approximately $5 million, and depreciation, depletion and amortization expense will decrease approximately $2 million.

Accounting Pronouncements

During 2002 and January 2003, the Financial Accounting Standards Board issued the following Statements of Financial Accounting Standards (SFAS) and Interpretations (FIN):

- SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* Effective April 1, 2002, we early adopted the provisions of SFAS No. 145 related to rescission of SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt,* by reporting such losses as non-extraordinary. SFAS No. 145 also amends the accounting for certain sale-leaseback transactions entered after May 15, 2002, and rescinds SFAS Nos. 44 and 64, and amends other pronouncements for technical corrections for financial statements issued after May 15, 2002. The effects of these other rescissions and amendments are not expected to have a material effect on our consolidated financial statements.
- SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* SFAS No. 146 requires that a liability for costs associated with exiting an activity (including restructurings) or disposal of long-lived assets be recognized when the liability is incurred and measured at the fair value of the liability. The provisions of SFAS No. 146 are required to be applied to exit or disposal activities initiated after December 31, 2002, and are not currently expected to have a material impact on our consolidated financial statements.
- SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure,* which amends SFAS No. 123, *Accounting for Stock-Based Compensation.* SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. The statement also amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The statement is required to be adopted for fiscal years ending after December 15, 2002.

A significant portion of our stock-based compensation is the award of performance shares, the fair value of which is fully expensed upon vesting when the target stock price is attained. We account for stock-based compensation in accordance with APB Opinion No. 25 and do not currently plan to expense stock option awards pursuant to SFAS 123. We have early implemented the disclosure requirements of SFAS No. 148. See Notes 1 and 12 to Consolidated Financial Statements.

- FIN No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* FIN No. 45 requires that a liability be recorded in the guarantor's balance sheet upon issuance of certain guarantees. Initial recognition and measurement of the liability will be applied on a prospective basis to guarantees issued or modified after December 31, 2002. FIN No. 45 also requires disclosures about guarantees in financial statements for interim or annual periods ending after December 15, 2002. FIN No. 45 is not expected to materially affect our consolidated financial statements. We have adopted the disclosure provisions of FIN No. 45 in our consolidated financial statements as of December 31, 2002.
- FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51.* FIN No. 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without financial support from other parties. We do not have an interest in, nor are we affiliated with, any variable interest entities, and therefore, do not expect the adoption of FIN No. 46 to have any impact on our consolidated financial statements.

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			
	2002		2001	
(in thousands)	Amount	Mcf	Amount	Mcf
Accounts receivable – current underproduction	$ 17,248	6,178	$ 13,497	5,079
Accounts payable – current overproduction	(14,381)	(5,165)	(13,064)	(4,871)
Net current gas underproduction balancing receivable	$ 2,867	1,013	$ 433	208
Other assets – noncurrent underproduction	$ 14,934	5,642	$ 15,763	6,018
Other long-term liability – noncurrent overproduction	(23,027)	(8,492)	(21,871)	(8,164)
Net long-term gas overproduction balancing payable	(8,093)	(2,850)	(6,108)	(2,146)
Other assets – noncurrent carbon dioxide underproduction	1,868	11,675	4,165	11,256
Net long-term overproduction balancing payable	$ (6,225)		$ (1,943)	

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, pricing differentials, operating costs, 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 and bank borrowing. Lower oil and gas prices, however, reduce cash flow and the amount of credit available under our bank revolving credit facility.

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, many of which have greater financial and other resources than us. In addition, the industry as a whole competes with other industries which supply energy and fuel to industrial, commercial and other consumers. 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. 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 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 or 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 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, 2002, our variable rate debt had a carrying value of $605 million, which approximated its fair value, and our fixed rate debt had a carrying value of $513.2 million and an approximate fair value of $541.6 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 interest rate swaps, 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	Hypothetical Change in Fair Value
December 31, 2002			
Long-term debt	$(1,118,170)	$(1,146,572)	$ 29,264[a]
December 31, 2001			
Long-term debt	$ (856,000)	$ (870,720)	$ 14,874[a]
Interest rate swaps	$ 2,791	$ 2,791	$ (809)[a]

(a) This is approximate gain in fair value of long-term debt and loss in fair value of interest rate swaps from a 100-basis point increase in interest rates. Because of the limitation in value caused by the call price of fixed rate debt, a 100-basis point decrease in interest rates would not significantly affect fair value at December 31, 2002 or December 31, 2001.

Commodity Price Risk

We hedge a portion of our price risks associated with our crude oil and natural gas sales. As of December 31, 2002, 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 $93.7 million at December 31, 2002 and a net fair value gain of $97.6 million at December 31, 2001. Of the December 31, 2002 fair value, a $107.5 million loss has been determined based on the exchange-trade value of NYMEX contracts and a $13.8 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, 2002, outstanding oil futures contracts and differential swaps had a net fair value loss of $2.7 million.

The aggregate effect of a hypothetical 10% change in gas prices would result in a change of approximately $68.1 million in the fair value of gas futures contracts and swap agreements at December 31, 2002. The aggregate effect of a hypothetical 10% change in oil prices would result in a change of approximately $1.5 million in the fair value of these oil futures contracts and differential swaps at December 31, 2002. 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, 2002 was $12.9 million. The effect of a hypothetical 10% change in gas prices would result in a change of approximately $3.2 million in the fair value of these contracts, while a 10% change in crude oil prices would result in a change of approximately $1.9 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, 2002.

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, the information called for by Items 10 through 13 is incorporated by reference from the Company's Notice of Annual Meeting and Proxy Statement to be filed with the Securities and Exchange Commission no later than April 30, 2003.

Item 10. Directors and Executive Officers of the Registrant

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management

Item 13. Certain Relationships and Related Transactions

Item 14. Controls and Procedures

We carried out 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 Rule 13a-14 within the 90 days before the filing of 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 IV

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

2. FINANCIAL STATEMENT SCHEDULES

Schedule II – Consolidated Valuation and Qualifying Accounts

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, 2002 and through March 20, 2003:

On November 26, 2002, we filed a report on Form 8-K dated November 25, 2002, to announce that we entered into a definitive agreement to acquire coalbed methane gas producing properties in the San Juan Basin of Colorado.

On December 18, 2002, we filed a report on Form 8-K dated December 17, 2002, to announce the final approval by the bankruptcy court to settle all outstanding claims with Enron North America Corporation.

On January 3, 2003, we filed a report on Form 8-K dated December 30, 2002, to announce the completion of the previously announced agreement to acquire coalbed methane gas producing properties in the San Juan Basin of Colorado.

On January 8, 2003, we filed a report on Form 8-K dated January 3, 2003 to announce that our Board of Directors approved a $400 million development and exploration budget for 2003.

(C) EXHIBITS

See Index to Exhibits at page 76 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 2002	December 31 2001
ASSETS		
Current Assets		
Cash and cash equivalents	$ 14,954	$ 6,810
Accounts receivable, net	145,356	111,101
Derivative fair value	40,628	107,526
Deferred income tax benefit	32,680	—
Other current assets	11,172	13,930
Total Current Assets	244,790	239,367
Property and Equipment, at cost – successful efforts method		
Producing properties	3,081,488	2,352,473
Undeveloped properties	12,163	9,545
Other	51,861	50,645
Total Property and Equipment	3,145,512	2,412,663
Accumulated depreciation, depletion and amortization	(774,547)	(571,276)
Net Property and Equipment	2,370,965	1,841,387
Other Assets		
Derivative fair value	1,032	18,174
Other	31,406	33,399
Total Other Assets	32,438	51,573
TOTAL ASSETS	$2,648,193	$2,132,327
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$ 150,107	$ 125,486
Payable to royalty trusts	6,466	2,233
Derivative fair value	128,001	1,024
Enron Btu swap contract	—	43,272
Current income taxes payable	517	600
Deferred income taxes payable	—	27,330
Other current liabilities	805	1,898
Total Current Liabilities	285,896	201,843
Long-term Debt	1,118,170	856,000
Other Long-term Liabilities		
Derivative fair value	22,953	28,331
Deferred income taxes payable	286,472	199,091
Other long-term liabilities	26,916	26,012
Total Other Long-term Liabilities	336,341	253,434
Commitments and Contingencies (Note 5)		
Stockholders' Equity		
Common stock ($.01 par value, 250,000,000 shares authorized, 180,979,976 and 175,984,977 shares issued)	1,810	1,760
Additional paid-in capital	534,354	484,654
Treasury stock (11,677,485 and 10,954,664 shares)	(76,561)	(64,714)
Retained earnings	509,756	328,712
Accumulated other comprehensive income (loss)	(61,573)	70,638
Total Stockholders' Equity	907,786	821,050
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$2,648,193	$2,132,327

See accompanying notes to consolidated financial statements.

XTO Energy Inc.
Consolidated Income Statements

(in thousands, except per share data)	Year Ended December 31 2002	2001	2000
REVENUES			
Oil and condensate	$115,324	$116,939	$128,194
Gas and natural gas liquids	681,147	710,348	456,814
Gas gathering, processing and marketing	11,622	12,832	16,123
Other	2,070	(1,371)	(280)
Total Revenues	810,163	838,748	600,851
EXPENSES			
Production	129,182	110,005	86,988
Taxes, transportation and other	57,225	63,656	56,696
Exploration	2,186	5,438	1,047
Depreciation, depletion and amortization	204,109	154,322	129,807
Gas gathering and processing	9,114	9,522	8,930
General and administrative	62,114	39,217	49,460
Derivative fair value (gain) loss	(2,599)	(54,370)	55,821
Total Expenses	461,331	327,790	388,749
OPERATING INCOME	348,832	510,958	212,102
OTHER INCOME (EXPENSE)			
Gain on significant property divestitures	—	—	29,965
Gain on investment in equity securities	—	—	13,279
Loss on extinguishment of debt	(8,528)	—	—
Interest expense, net	(53,555)	(55,601)	(78,914)
Total Other Income (Expense)	(62,083)	(55,601)	(35,670)
INCOME BEFORE INCOME TAX, MINORITY INTEREST AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	286,749	455,357	176,432
Income tax expense	100,690	161,952	59,380
Minority interest in net income of consolidated subsidiaries	—	—	(59)
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	186,059	293,405	116,993
Cumulative effect of accounting change, net of tax	—	(44,589)	—
NET INCOME	186,059	248,816	116,993
Preferred stock dividends	—	—	1,758
EARNINGS AVAILABLE TO COMMON STOCK	$186,059	$248,816	$115,235
EARNINGS PER COMMON SHARE			
Basic			
Net income before cumulative effect of accounting change	$ 1.12	$ 1.79	$ 0.81
Cumulative effect of accounting change	—	(0.27)	—
Earnings available to common stock	$ 1.12	$ 1.52	$ 0.81
Diluted			
Net income before cumulative effect of accounting change	$ 1.10	$ 1.77	$ 0.77
Cumulative effect of accounting change	—	(0.27)	—
Earnings available to common stock	$ 1.10	$ 1.50	$ 0.77
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	166,700	163,340	142,307

See accompanying notes to consolidated financial statements.

XTO Energy Inc.
Consolidated Statements of Cash Flows

(in thousands)	Year Ended December 31 2002	2001	2000
OPERATING ACTIVITIES			
Net income	$ 186,059	$ 248,816	$ 116,993
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	204,109	154,322	129,807
Non-cash incentive compensation	26,990	9,246	25,790
Deferred income tax	100,368	161,105	58,993
(Gain) loss on investment in equity securities and from sale of properties	(129)	277	(45,578)
Non-cash derivative fair value (gain) loss	6,890	(69,147)	54,512
Minority interest in net income of consolidated subsidiaries	—	—	59
Cumulative effect of accounting change, net of tax	—	44,589	—
Loss on extinguishment of debt	8,528	—	—
Enron settlement – non-cash gain and revenue	(16,142)	—	—
Other non-cash items	(2,955)	(5,079)	3,015
Changes in operating assets and liabilities [a]	(22,876)	(1,514)	33,830
Cash Provided by Operating Activities	490,842	542,615	377,421
INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	149	319	77,119
Property acquisitions	(358,087)	(224,906)	(45,648)
Development costs	(370,558)	(381,026)	(154,382)
Other property and asset additions	(8,321)	(13,438)	(11,033)
Officer loan repayments	—	8,128	60
Cash Used by Investing Activities	(736,817)	(610,923)	(133,884)
FINANCING ACTIVITIES			
Proceeds from long-term debt	1,156,000	640,000	523,400
Payments on long-term debt	(893,830)	(553,000)	(745,500)
Dividends	(4,984)	(4,413)	(3,891)
Senior note offering costs	(8,381)	—	—
Net proceeds from exercise of stock options and warrants	22,305	2,608	11,202
Subordinated note redemption costs	(3,794)	—	—
Purchase of minority interest	—	—	(100,071)
Common stock offering	—	—	126,125
Purchases of treasury stock and other	(13,197)	(17,515)	(53,098)
Cash Provided (Used) by Financing Activities	254,119	67,680	(241,833)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	8,144	(628)	1,704
Cash and Cash Equivalents, January 1	6,810	7,438	5,734
Cash and Cash Equivalents, December 31	$ 14,954	$ 6,810	$ 7,438

[a] Changes in Operating Assets and Liabilities

	2002	2001	2000
Accounts receivable	$ (19,088)	$ 58,706	$ (90,921)
Investment in equity securities	—	—	43,746
Other current assets	2,758	(3,855)	(4,535)
Other assets	4,293	(1,738)	(15,535)
Enron Btu swap contract	(43,272)	—	—
Current liabilities	32,433	(54,627)	82,392
Other long-term liabilities	—	—	18,683
	$ (22,876)	$ (1,514)	$ 33,830

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 (Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
BALANCES, DECEMBER 31, 1999	$ 28,468	$1,746	$395,404	$(119,387)	$ (28,414)	$ —	$277,817
Net income	—	—	—	—	116,993	—	116,993
Sale of common stock from treasury	—	—	61,427	64,698	—	—	126,125
Issuance/vesting of performance shares	—	16	18,236	(6,976)	—	—	11,276
Stock option exercises, including income tax benefits	—	64	29,944	(4,933)	—	—	25,075
Treasury stock purchases	—	—	—	(55,758)	—	—	(55,758)
Cancellation of shares	—	(178)	(71,349)	71,527	—	—	—
Common stock dividends ($0.0167 per share)	—	—	—	—	(2,403)	—	(2,403)
Preferred stock converted to common	(1,251)	4	1,247	—	—	—	—
Preferred stock dividends ($1.56 per share)	—	—	—	—	(1,758)	—	(1,758)
BALANCES, DECEMBER 31, 2000	27,217	1,652	434,909	(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 taxes of $69,153	—	—	—	—	—	128,428	128,428
Hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of applicable taxes of $5,133	—	—	—	—	—	9,533	9,533
Comprehensive income							319,454
Issuance/vesting of performance shares	—	9	5,182	(4,226)	—	—	965
Stock option exercises, including income tax benefits	—	28	17,417	(410)	—	—	17,035
Treasury stock purchases	—	—	—	(9,249)	—	—	(9,249)
Common stock dividends ($0.0275 per share)	—	—	—	—	(4,522)	—	(4,522)
Preferred stock converted to common	(27,217)	71	27,146	—	—	—	—
BALANCES, DECEMBER 31, 2001	—	1,760	484,654	(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	—	13	25,605	(10,276)	—	—	15,342
Stock option and warrant exercises, including income tax benefits	—	37	24,095	(35)	—	—	24,097
Treasury stock purchases	—	—	—	(1,536)	—	—	(1,536)
Common stock dividends ($0.0300 per share)	—	—	—	—	(5,015)	—	(5,015)
BALANCES, DECEMBER 31, 2002	$ —	$1,810	$534,354	$ (76,561)	$509,756	$(61,573)	$907,786

See accompanying notes to consolidated financial statements.

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 four-for-three stock split effected on March 18, 2003 and the three-for-two stock splits effected on September 18, 2000 and 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.

As of April 1, 2002, we early adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections,* related to rescission of SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt,* by reporting such losses (Note 3) as non-extraordinary.

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 $62,384,000 at December 31, 2002 and $136,611,000 at December 31, 2001 related to wells in process of drilling.

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 and equipment is compared to management's future estimated pre-tax cash flow. If impairment is necessary, the asset carrying value is adjusted 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.

New Retirement Obligation Accounting Principle

Effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires that the fair value of the liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate can be made. 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 the offsetting charge to property cost. Periodic accretion of discount of the estimated liability is recorded 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 and depreciation. 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.

We have used an expected cash flow approach to estimate our asset retirement obligation under SFAS No. 143. As of the January 1, 2003 adoption date, we estimate a retirement obligation of $75 million, an increase in property cost of $61 million, a reduction of accumulated depreciation, depletion and amortization of $17 million and a cumulative effect of accounting change gain, net of tax, of $2 million. As a result of adoption of SFAS No. 143, we estimate that in 2003 accretion of discount expense will be approximately $5 million, and depreciation, depletion and amortization expense will decrease approximately $2 million.

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 22.7% of Cross Timbers Royalty Trust as a result of units we purchased on the open market from 1996 through 1998, and 54.3% of the Hugoton Royalty Trust, which is the portion we retained following our sale of units in 1999 and 2000. The cost of our interest in the trusts is included in producing properties. Amounts due the trusts, net of amounts retained by our ownership of 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.

Investment in Equity Securities

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* we recorded equity securities held during 2000 as trading securities since they were acquired principally for resale in the near future. Accordingly, unrealized gains and losses are recorded in the consolidated income statements, and cash flows from purchases and sales of equity securities are included in cash provided by operating activities in the consolidated statements of cash flows. Gains (losses) on trading securities and interest expense related to the cost of these investments were classified as other income (expense) in the consolidated income statements.

Other Assets

Other assets primarily include deferred debt costs that are amortized over the term of the related debt (Note 3) and the long-term portion of gas balancing receivable (see "Revenue Recognition" below). 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 $18,338,000 at December 31, 2002 and $16,194,000 at December 31, 2001.

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 and 138 (Note 6). 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.

Changes in fair value of derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, are recorded as a derivative fair value gain or loss in the income statement. Changes in fair value of effective cash flow hedges, as well as any gain or loss realized upon early termination of effective hedge derivatives, are recorded as a component of accumulated other comprehensive income. These deferred gains and losses are later transferred to earnings when the hedged transaction occurs. At that time, 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. Cash flows related to derivative transactions are included in operating activities.

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 deferred 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 receive 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			
	2002		2001	
(in thousands)	Amount	Mcf	Amount	Mcf
Accounts receivable – current underproduction	$ 17,248	6,178	$ 13,497	5,079
Accounts payable – current overproduction	(14,381)	(5,165)	(13,064)	(4,871)
Net current gas underproduction balancing receivable	$ 2,867	1,013	$ 433	208
Other assets – noncurrent underproduction	$ 14,934	5,642	$ 15,763	6,018
Other long-term liability – noncurrent overproduction	(23,027)	(8,492)	(21,871)	(8,164)
Net long-term gas overproduction balancing payable	(8,093)	(2,850)	(6,108)	(2,146)
Other assets – carbon dioxide underproduction	1,868	11,675	4,165	11,256
Net long-term overproduction balancing payable	$ (6,225)		$ (1,943)	

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 $55,595,000 for 2002, $108,590,000 for 2001 and $144,282,000 for 2000. These amounts are net of inter-company 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 Statement of Financial Accounting Standards 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. See Note 5.

Interest

Interest expense includes amortization of deferred debt costs and is presented net of interest income of $836,000 in 2002, $716,000 in 2001 and $1,430,000 in 2000, and net of capitalized interest of $4,330,000 in 2002, $6,649,000 in 2001 and $3,488,000 in 2000. Interest is capitalized as producing property cost based on the weighted average interest rate and the cost of wells in process of drilling. Interest expense related to investment in equity securities has been classified as a component of gain (loss) on investment in equity securities.

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:*

	Year Ended December 31		
(in thousands, except per share data)	2002	2001	2000
Earnings available to common stock as reported	$186,059	$248,816	$115,235
Add			
Stock-based compensation expense included in the income statement, net of related tax effects	17,543	5,674	12,134
Deduct			
Total stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(19,762)	(49,947)	(36,175)
Pro forma net income	$183,840	$204,543	$ 91,194
Earnings per share			
Basic – as reported	$ 1.12	$ 1.52	$ 0.81
Basic – pro forma	$ 1.10	$ 1.25	$ 0.64
Diluted – as reported	$ 1.10	$ 1.50	$ 0.77
Diluted – pro forma	$ 1.09	$ 1.23	$ 0.61

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. All of our assets are located in the United States, and all revenues are attributable to United States customers.

Production is sold under contracts with various purchasers. 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. For the year ended December 31, 2000, sales to a single purchaser were approximately 13% 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.

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 402,000 shares of our common stock from the officers for $6.5 million.

OTHER TRANSACTIONS

A company, partially owned by one of our directors, 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 received fees totaling $994,000 in 2000 for consulting services performed in connection with our acquisition and divestiture programs.

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 outstanding debt consists of the following:

(in thousands)	December 31 2002	2001
LONG-TERM DEBT		
Senior debt		
Bank debt under revolving credit agreements due May 12, 2005, 2.84% at December 31, 2002	$ 605,000	$556,000
7 1/2% senior notes due April 15, 2012	350,000	—
Subordinated debt		
9 1/4% senior subordinated notes due April 1, 2007	—	125,000
8 3/4% senior subordinated notes due November 1, 2009	163,170	175,000
Total long-term debt	$1,118,170	$856,000

SENIOR DEBT

In May 2000, we entered a revolving credit agreement with commercial banks with a commitment of $800 million. Borrowings at December 31, 2002 under the loan agreement were $605 million with unused borrowing capacity of $195 million. The borrowing base is redetermined annually based on the value and expected cash flow of our proved oil and gas reserves. If borrowings exceed the redetermined borrowing base, the banks may require that the excess be repaid within a year. Based on reserve values at December 31, 2002 and using parameters specified by the banks, the borrowing base remains in excess of the $800 million commitment. Borrowings under the loan agreement are due May 12, 2005, but may be prepaid at any time without penalty. We may renegotiate the loan agreement to increase the borrowing commitment and extend the revolving facility.

The revolving credit facility is partially secured by our producing properties. Restrictions set forth in the loan agreement include limitations on the incurrence of additional indebtedness and the creation of certain liens. The loan agreement also limits dividends and treasury stock purchases to 25% of cash flow from operations, as defined, for the latest four consecutive quarterly periods. We are also required to maintain a current ratio of not less than one (where unused borrowing commitments are included as a current asset and derivative fair value assets and liabilities are excluded).

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 London Interbank Offered Rates ("LIBOR"). Borrowings under the loan agreement at December 31, 2002 were based on LIBOR rates with maturity of one to six months and accrued at the applicable LIBOR rate plus 1.375%. 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 0.25% at December 31, 2002. The weighted average interest rate on senior debt was 3.2% during 2002, 5.7% during 2001 and 8.2% during 2000.

In April 2002, we sold $350 million of 7 1/2% senior notes due in 2012. The notes are general unsecured senior indebtedness ranking above our senior subordinated notes, but effectively subordinate to our secured bank borrowings. The senior notes require no sinking fund payments. Net proceeds of $341.6 million from the sale of notes were used to finance property transactions (Note 13), to redeem our 9 1/4% senior subordinated notes and to reduce bank debt.

SUBORDINATED DEBT

In April 1997, we sold $125 million of 9 1/4% senior subordinated notes due April 2007, and in October 1997, we sold $175 million of 8 3/4% senior subordinated notes due November 2009. Interest on the notes are paid semiannually. The notes are general unsecured indebtedness that is subordinate to bank borrowings under the loan agreement. Net proceeds of $121.1 million from the 9 1/4% notes and $169.9 million from the 8 3/4% notes were used to reduce bank borrowings under the loan agreement.

Under the terms of an agreement with a bank counterparty, we purchased and canceled $9.7 million of 9 1/4% senior subordinated notes on April 1, 2002. In June 2002, we redeemed the remaining $115.3 million 9 1/4% notes at a redemption price of 104.625%, or $120.6 million, plus accrued interest of $1.8 million. As a result of these transactions, we recorded a pre-tax loss on extinguishment of debt of $7.8 million.

Under the terms of an agreement with a bank counterparty, we purchased and canceled $11.8 million of 8 3/4% senior subordinated notes on November 1, 2002. Including the effects of this agreement and expensing of related deferred debt cost, we recorded a pre-tax loss on extinguishment of debt of $700,000 in fourth quarter 2002.

As of December 31, 2002, we have the option to redeem the 8 3/4% notes at a price of approximately 104%, and thereafter at prices declining ratably each year to 100% in 2005. Upon a change in control of the Company, the noteholders have the right to require us to purchase all or a portion of their notes at 101% plus accrued interest.

The notes were issued under indentures that place certain restrictions on us, including limitations on additional indebtedness, liens, dividend payments, treasury stock purchases, disposition of proceeds from asset sales, transfers of assets and transactions with subsidiaries and affiliates.

4. Income Tax

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

(in thousands)	2002	2001	2000
Income tax expense at the federal statutory rate (35% in 2002 and 2001 and 34% in 2000)	$100,362	$159,375	$59,987
State and local income taxes and other	328	2,577	(607)
Income tax expense	$100,690	$161,952	$59,380

Components of income tax expense are as follows:

(in thousands)	2002	2001	2000
Current income tax	$ 322	$ 847	$ 387
Deferred income tax expense	121,396	159,257	63,792
Net operating loss carryforwards (added) used	(21,028)	1,848	(4,799)
Income tax expense	$100,690	$161,952	$59,380

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 liabilities are recorded as a current asset of $32,680,000 and a long-term liability of $286,472,000 at December 31, 2002 and as a current liability of $27,330,000 and a long-term liability of $199,091,000 at December 31, 2001. Significant components of net deferred tax assets and liabilities are:

	December 31	
(in thousands)	2002	2001
Deferred tax assets		
Net operating loss carryforwards	$ 88,549	$ 67,521
Derivative fair value loss	52,834	25,940
Other	7,981	5,993
Total deferred tax assets	149,364	99,454
Deferred tax liabilities		
Property and equipment	374,614	265,588
Derivative fair value gain	14,581	48,646
Other	13,961	11,641
Total deferred tax liabilities	403,156	325,875
Net deferred tax liabilities	$(253,792)	$(226,421)

As of December 31, 2002, we had estimated tax loss carryforwards of approximately $267 million, of which $10.4 million are related to capital losses. The capital loss tax carryforwards expire in 2005 while the remaining ordinary loss carryforwards are scheduled to expire in 2010 through 2022. Approximately $22 million of the tax loss carryforwards are the result of an acquisition. We have not booked any valuation allowance because we believe we have tax planning strategies available to realize our tax loss carryforwards.

5. 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, 2002, minimum future lease payments for all noncancelable lease agreements (including the sale and operating leaseback agreements described below) were as follows:

(in thousands)	
2003	$16,716
2004	13,103
2005	10,195
2006	10,105
2007	10,236
Remaining	31,434
Total	$91,789

Amounts incurred under operating leases (including renewable monthly leases) were $26.6 million in 2002, $20.6 million in 2001 and $17.3 million in 2000.

In February 2003, we entered a 12-year operating lease for an airplane with annual rentals of $1.1 million for the first six years and $1.4 million for the remaining term.

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 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, 2002, 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, 2002 was $1.3 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.

Guarantees

Under the terms of some of our operating leases, 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, 2002, we estimate the total contingent payable under these guarantees does not exceed $5 million.

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 natural gas physical delivery contracts, 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 2003 with total commitments under the agreements of $42.5 million. Early termination of these contracts would require a termination fee of $7.5 million in lieu of these commitments.

Litigation

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 allege 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 allege that these actions reduced the royalties paid to the plaintiffs and those similarly situated, and that such actions are a breach of the leases under which the royalties are paid. These deductions allegedly include production and post-production costs, marketing costs, administration costs and costs incurred by us in gathering, compressing, dehydrating, processing, treating, blending and/or transporting the gas produced. We contend that, to the extent any fees are proportionately borne by the plaintiffs, these fees are established by arm's-length negotiations with third parties or, if charged by affiliates, are comparable to fees charged by third party gatherers or processors. We further contend that any such fees enhance the value of the gas or the products derived from the gas. The parties have signed a settlement agreement under which we will pay $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, is $2.1 million, which has been accrued in our financial statements. The court has tentatively approved the settlement, subject to a fairness hearing in April 2003.

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. According to the U.S. Department of Justice, the plaintiff has made similar allegations in over 70 actions filed against more than 300 other companies. 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 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. We have reached a tentative settlement with the Department of Interior to pay $288,000 in settlement of all claims. The settlement should be finalized in second quarter 2003. Management's estimate of the potential liability from this claim 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 on whether to certify the case as a class action was held in January 2003, and the decision of the court is pending. 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.

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.

6. 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, *Accounting for Derivative Instruments and Hedging Activities,* as amended by SFAS Nos. 137 and 138, by recording a one-time after-tax charge of $44,589,000 in the income statement for the cumulative effect of a change in accounting principle and an unrealized loss of $67,323,000 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.

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 (Note 8). This contract was terminated as a result of the Enron bankruptcy (Note 7). 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 was 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 2004 and from crude oil sales through December 2003. See Note 8.

Interest Rate Swap Agreements

To reduce the interest rate on a portion of our subordinated debt, we entered an agreement with a bank to purchase a portion of our subordinated notes with a face value of $21.6 million. We paid the bank a variable interest rate based on three-month LIBOR rates, and received semiannually from the bank the fixed interest rate on the notes. These agreements terminated during 2002 and we purchased the related subordinated notes at their face value. See Note 3.

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)	2002	2001	2000
Change in fair value of Btu swap contracts	$ 1,046	$(23,428)	$ —
Change in fair value of call options and other derivatives that do not qualify for hedge accounting	(6,505)	(31,099)	55,821
Ineffective portion of derivatives qualifying for hedge accounting	2,860	157	—
Derivative fair value (gain) loss	$(2,599)	$(54,370)	$55,821

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, 2002 and 2001. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2002		December 31, 2001	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivative Assets				
Fixed-price natural gas futures and swaps	$ 41,483	$ 41,483	$ 116,829	$ 116,829
Fixed-price crude futures and differential	177	177	—	—
Interest rate swap	—	—	2,791	2,791
Btu swap contracts	—	—	6,080	6,080
Derivative Liabilities				
Fixed-price natural gas futures and swaps	(135,188)	(135,188)	(19,198)	(19,198)
Fixed-price crude futures and differential	(2,886)	(2,886)	—	—
Btu swap contracts	(12,880)	(12,880)	(10,157)	(10,157)
Net derivative asset (liability)	$ (109,294)	$ (109,294)	$ 96,345	$ 96,345
Long-term debt	$(1,118,170)	$(1,146,572)	$(856,000)	$(870,720)

The fair value of bank borrowings approximates their carrying value because of short-term interest rate maturities. The fair value of subordinated long-term debt is based on current market quotes. The fair value of futures contracts, swap agreements and call options is estimated based on the exchange-trade value of NYMEX contracts, market commodity prices and interest rates 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.

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. 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 $5,537,000 at December 31, 2002 and $4,098,000 at December 31, 2001. Our bad debt provision was $980,000 in 2002, $978,000 in 2001 and $1,093,000 in 2000.

7. Enron Corporation Bankruptcy

As of December 2, 2001, the date of its bankruptcy filing, Enron Corporation was the counterparty to some of our hedge derivative contracts, as well as a purchaser of natural gas under certain physical delivery contracts. One of these contracts was the Enron Btu swap contract (Note 6).

We sent Enron notices of contract terminations in November and December 2001. Based on the fair value as of the contract termination dates, Enron owed us $7.8 million for physical gas deliveries in November and December 2001, and $13.5 million for net gains on hedge derivative contracts. These amounts were recorded in the balance sheet at December 31, 2001. Enron also owed us $14.1 million in net unrealized gains related to undelivered gas under physical delivery contracts, which was not recorded in the December 31, 2001 financial statements. Also recorded in the balance sheet at December 31, 2001 was a current liability of $43.3 million related to the Enron Btu swap contract, based on fair values at the date of contract termination.

In December 2002, we paid Enron $6 million in settlement of all obligations between both parties. As a result of this settlement, we recognized $14.1 million in additional gas revenue related to physical delivery contracts and a gain of $2.1 million.

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 predictable, stable cash flows.

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 6 regarding accounting for commodity hedges.

	Futures Contracts and Swap Agreements	
Production Period	Mcf per Day	Average NYMEX Price per Mcf
2003 April to June	450,000	$3.97
July to December	400,000	3.99
2004 January to December	150,000	4.15

We have closed certain futures contracts and swap agreements that were designated as cash flow hedges with deferred gains of $13.3 million recorded in accumulated other comprehensive income. These deferred gains will be recognized as gas revenue of $0.28 per Mcf on production of 175,000 Mcf per day from April through December 2003.

In January 2003, we entered collar agreements which provide a floor (put) and ceiling (call) price for natural gas. If the market price of natural gas exceeds the ceiling price, we pay the counterparty the difference between these prices. If the market price of natural gas is between the floor and ceiling price, no payments are due from either the Company or the counterparty. If the floor price exceeds the market price, we receive from the counterparty the difference between these prices. Prices to be realized are expected to be less than these floor and ceiling prices because of location, quality and other adjustments. We have entered into collar agreements for April to December 2003 on 50,000 Mcf per day with a floor price of $4.50 per Mcf and a ceiling price of $5.57 per Mcf.

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

	Location					
Production Period	**Arkoma**	**Houston Ship Channel**	**Mid-Continent**	**Rockies**	**San Juan Basin**	**Total**
2003						
April to June						
Mcf per day	70,000	240,000	40,000	15,000	40,000	405,000
Basis per Mcf [(a)]	$ (0.11)	$ (0.02)	$ (0.17)	$ (0.57)	$ (0.38)	
July to October						
Mcf per day	70,000	200,000	40,000	15,000	40,000	365,000
Basis per Mcf [(a)]	$ (0.11)	$ (0.02)	$ (0.17)	$ (0.57)	$ (0.38)	
November to December						
Mcf per day	10,000	180,000	20,000	5,000	20,000	235,000
Basis per Mcf [(a)]	$ (0.07)	$ (0.03)	$ (0.20)	$ (0.65)	$ (0.40)	
2004						
January to March						
Mcf per day	30,000	50,000	10,000	5,000	20,000	115,000
Basis per Mcf [(a)]	$ (0.10)	$ (0.04)	$ (0.15)	$ (0.65)	$ (0.40)	
April to December						
Mcf per day	20,000	—	—	—	—	20,000
Basis per Mcf [(a)]	$ (0.11)	—	—	—	—	

(a) Reductions to NYMEX gas prices for location, quality and other adjustments.

In 2002, net gains on futures, collars and basis swap hedge contracts increased gas revenue by $57.4 million. Including the effect of fixed price physical delivery contracts, all hedging activities increased gas revenue by $95.4 million. During 2001, net losses on futures and basis swap hedge contracts reduced gas revenue by $11.1 million. Including the effect of fixed price physical delivery contracts, all hedging activities increased gas revenue by $97 million during 2001. During 2000, net losses on futures and basis hedge contracts reduced gas revenue by $40.5 million. As of December 31, 2002, an unrealized pre-tax derivative fair value loss of $92.1 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income. Of this year-end fair value loss of $92.1 million, $80 million is expected to be reclassified into earnings in 2003.

The settlement of futures contracts and basis swap agreements related to first quarter 2003 gas production resulted in reduced gas revenue of approximately $106 million, or $2.00 per Mcf.

Crude Oil

In 2002, we entered oil futures contracts to sell 6,000 Bbls per day from August through December 2002 at an average NYMEX price of $26.57 per barrel and from January through March 2003 at an average NYMEX price of $25.58 per barrel. We also entered a sour oil basis swap on 5,000 Bbls of oil per day from August 2002 through June 2003 at the NYMEX West Texas Intermediate price less $1.25 per Bbl to effectively fix quality and other price differentials. Because this basis swap agreement includes an extendable option, it does not qualify for hedge accounting.

In 2002, net losses on the futures hedge contracts decreased oil revenue by $1.3 million, while changes in fair value of the basis swap contracts resulted in a derivative fair value gain of $300,000. During 2000, net losses on futures contracts reduced oil revenue by $7.8 million. As of December 31, 2002, an unrealized pre-tax derivative fair value loss of $2.6 million, related to cash flow hedges of oil price risk, was recorded in accumulated other comprehensive income. The ultimate settlement value of these hedges will be recognized in the income statement as oil revenue when the hedged oil sales occur through June 2003. In January and February 2003, net losses on the futures hedge contracts decreased oil revenue by $3 million, and changes in fair value of the basis swap contracts resulted in a derivative fair value gain of $500,000.

In February 2003, we entered crude oil costless three-way collars for 2,000 Bbls per day for April through December 2003. These collars effectively provide a ceiling price and a floating minimum price as follows:

	NYMEX WTI Price		
2003 Production Period	**Ceiling**	**Provisional Floor [(a)]**	**Strike [(a)]**
April	$35.02	$31.67	$25.27
May	33.80	30.45	24.05
June	32.87	29.52	23.12
July	32.01	28.66	22.26
August	31.31	27.96	21.56
September	30.81	27.46	21.06
October	30.40	27.05	20.65
November	30.04	26.69	20.29
December	29.48	26.13	19.73

(a) At market prices within the range of the provisional floor and strike price, we will receive payment from the counterparty to effectively receive the provisional floor price. At market prices below the strike price, we will receive the market price plus $6.40, the spread between the provisional floor and strike price.

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 6 regarding accounting for this contract, also referred to as the Enron Btu swap contract, which was terminated as a result of the Enron bankruptcy (Note 7), and regarding a related derivative commitment with another counterparty.

As partial consideration for an acquisition, we agreed to sell gas volumes ranging from 40,000 Mcf per day in 2000 to 35,000 Mcf per day in 2003 at specified discounts from index prices. This commitment was recorded at its total value of $7.5 million in March 1999 in other current and long-term liabilities. The discounts are charged to the liability as taken. As of December 31, 2002, $459,000 is recorded in other current liabilities related to the remaining commitment.

As part of an acquisition, we assumed a commitment to sell 6,800 Mcf of gas per day in Arkansas through April 2003 at prices which are adjusted by the monthly index price. In 2002, the prices ranged from $0.46 to $0.72 per Mcf. This contract is considered a normal sale and therefore, is not recorded as a derivative in our financial statements.

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 (Note 13). 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 three-for-two common stock splits on September 18, 2000 and June 5, 2001, and a four-for-three stock split on March 18, 2003. 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:

	Shares Issued			Shares in Treasury		
(in thousands)	2002	2001	2000	2002	2001	2000
Balance, January 1	175,985	165,173	174,565	10,955	10,063	27,899
Issuance/sale of common stock	—	—	—	—	—	(13,200)
Issuance/vesting of performance shares	1,334	888	1,627	627	289	761
Stock option and warrant exercises	3,661	2,872	6,389	2	31	552
Treasury stock purchases	—	—	—	93	572	11,783
Cancellation of shares	—	—	(17,732)	—	—	(17,732)
Preferred stock converted to common	—	7,052	324	—	—	—
Balance, December 31	180,980	175,985	165,173	11,677	10,955	10,063

In May 2000, 17.7 million shares were canceled from treasury stock. This transaction caused a $71.5 million reduction in treasury stock with an offsetting reduction in additional paid-in capital, resulting in no change to total stockholders' equity.

In November 2000, we sold from treasury 13.2 million shares of common stock in an underwritten public offering for net proceeds of approximately $126.1 million. The proceeds were used to reduce bank debt.

TREASURY STOCK

Our open market treasury share acquisitions totaled 10.5 million shares in 2000 at an average price of $3.94. As of March 20, 2003, 8.6 million shares remain under the May 2000 Board of Directors' authorization to repurchase 9 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, a dividend of one preferred share purchase right was declared for each outstanding share of common stock, par value $0.01 per share, payable on September 15, 1998 to stockholders of record on that date. 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 ten years.

SHELF REGISTRATION STATEMENT

In October 2001, 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 price of securities that can be offered is $600 million, 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. After we sold $350 million of 7 ½% senior notes in April 2002, $250 million remains available for future offerings under the shelf registration statement (Note 3).

Common Stock Warrants

As partial consideration for producing properties acquired in December 1997, we issued warrants to purchase 2.9 million shares of common stock at a price of $5.03 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 $0.0033 per common share for the first and second quarter 2000, $0.0050 per common share for each quarter from the third quarter 2000 through first quarter 2001 and $0.0075 per common share each quarter for the remainder of 2001 and 2002. In February 2003, the Board of Directors declared a first quarter 2003 dividend of $0.01 per share. See Note 3 regarding restrictions on dividends.

Series A Convertible Preferred Stock

During 2000, 50,000 shares of convertible preferred stock were converted into 324,000 shares of common stock. In 2001, 1.1 million outstanding shares of preferred stock were converted into 7.1 million common shares.

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
2002			
Basic	$186,059	166,700	$1.12
Effect of dilutive securities			
Stock options	—	827	
Warrants [a]	—	1,125	
Diluted	$186,059	168,652	$1.10
2001			
Basic	$248,816	163,340	$1.52
Effect of dilutive securities			
Stock options	—	645	
Preferred stock	—	503	
Warrants	—	1,680	
Diluted	$248,816	166,168	$1.50
2000			
Basic	$116,993		
Preferred stock dividends	(1,758)		
Earnings available to common stock – basic	115,235	142,307	$0.81
Effect of dilutive securities			
Stock options	—	1,036	
Preferred stock	1,758	7,293	
Warrants	—	775	
Diluted	$116,993	151,411	$0.77

(a) All outstanding warrants were exercised in August 2002 (Note 9). Dilutive effect is related to periods prior to exercise.

11. Supplemental Cash Flow Information

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

- Conversion of 1.1 million shares of preferred stock to 7.1 million shares of common stock in 2001 and conversion of 50,000 shares of preferred stock to 324,000 shares of common stock in 2000
- Cancellation of 17.7 million shares of treasury stock in 2000
- Sale of Hugoton Royalty Trust units in 2000 in exchange for 991,000 shares of common stock valued at \$11.3 million
- Performance shares activity, including:
  - Grants of 1,423,000 shares in 2002, 1,171,000 shares in 2001 and 1,639,000 shares in 2000 to key employees and nonemployee directors
  - Vesting of 1,663,000 shares in 2002, 802,000 shares in 2001 and 2,013,000 shares in 2000
  - Forfeiture of 12,000 shares in 2001
  - Receipt of 88,000 shares of common stock (valued at \$967,000) in 2000 for the option price of exercised stock options

Interest payments in 2002 totaled \$52,094,000 (including \$4,330,000 of capitalized interest), \$59,550,000 in 2001 (including \$6,649,000 of capitalized interest) and \$80,067,000 in 2000 (including \$3,488,000 of capitalized interest). Net income tax payments were \$405,000 during 2002 and \$1,085,000 during 2000; income tax refunds were \$140,000 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 \$4,478,000 in 2002, \$3,884,000 in 2001 and \$3,226,000 in 2000.

POST-RETIREMENT HEALTH PLAN

Effective January 1, 2001, we adopted a retiree medical plan for employees who retire at age 55 or over with a minimum of five years full-time service. Benefits under the plan are the same as for active employees, and continue until the retired employee or the employee'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 2002 and 2001 is as follows:

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

The weighted average discount rate used by us in determining the accumulated post-retirement benefit obligation was 6.5%. For measurement purposes, the annual rate of increase in the covered health care benefits was assumed to range from 9% in 2002 to 6% in 2008 and beyond. A 1% change in the assumed health care cost trend rate would have approximately a $100,000 effect on total estimated service and interest cost and approximately a $400,000 effect on the post-retirement benefit obligation. Unrecognized net actuarial loss and prior service costs will be amortized to expenses over the average remaining service life of approximately seven years. Including such amortization, the 2003 accrued benefit cost is expected to be $1.4 million.

1994 and 1997 Stock Incentive Plans

Under the 1994 Stock Incentive Plan and the 1997 Stock Incentive Plan, 6,750,000 shares of common stock were available to be issued under each plan pursuant to grants of stock options or performance shares. As of August 2002, all options granted under the 1994 Plan and the 1997 Plan were exercised. The Board of Directors terminated both of the plans in November 2002.

1998 Stock Incentive Plan

Under the 1998 Stock Incentive Plan, a total of 18,000,000 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 8,536,000 options outstanding at December 31, 2002 that are exercisable and 306,000 options outstanding that vest when the common stock price reaches $20.63. At December 31, 2002, there were 495,000 shares available for grant under the 1998 Plan.

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 totaling 1,412,000 in 2002, 1,162,000 in 2001 and 1,639,000 in 2000. Performance shares vested, totaling 1,652,000 in 2002, 793,000 in 2001 and 2,013,000 in 2000, when the common stock price reached specified levels. In 2001, 12,000 of the performance shares issued in 2001 were forfeited. General and administrative expense includes compensation related to performance shares of $27 million in 2002, $8.7 million in 2001 and $18.4 million in 2000. Treasury stock purchases related to the 2002 vested performance shares totaled $10.3 million in 2002, $4.2 million in 2001 and $7.1 million in 2000. As of December 31, 2002, there were 200,000 performance shares that vest when the common stock price reaches $20.00, 104,000 performance shares that vest when the common stock price reaches $20.63 and 9,000 performance shares that vest in 2003. We also issued to nonemployee directors a total of 11,000 performance shares in 2003, 11,000 performance shares in 2002 and 9,000 performance shares in 2001, all of which vested upon grant.

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 200,000 performance shares for every $1.25 increment in the closing price of our common stock above $15.00. 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 310,000 performance shares immediately prior to a change in control without regard to the price of our common stock.

Royalty Trust Option Plan

Under the 1998 Royalty Trust Option Plan, we granted certain officers options to purchase 1,290,000 Hugoton Royalty Trust units at prices of $8.03 and $9.50 per unit, or a total of $12 million. Most of these options were exercised in 2000, resulting in non-cash compensation expense of $7.1 million. The Board of Directors terminated the plan in May 2002.

Option Activity and Balances

The following summarizes option activity and balances from 2000 through 2002:

	Weighted Average Exercise Price	Stock Options
2000		
Beginning of year	$ 4.60	9,029,472
Grants	10.00	9,525,003
Exercises	4.91	(9,286,808)
Forfeitures	4.46	(492,704)
End of year	10.07	8,774,963
Exercisable at end of year	9.62	6,297,019
2001		
Beginning of year	$10.07	8,774,963
Grants	14.06	7,618,161
Exercises	9.89	(7,100,873)
Forfeitures	14.11	(108,000)
End of year	13.45	9,184,251
Exercisable at end of year	13.52	8,656,251
2002		
Beginning of year	$13.45	9,184,251
Grants	17.07	657,349
Exercises	10.86	(954,863)
Forfeitures	13.16	(43,838)
End of year	14.00	8,842,899
Exercisable at end of year	13.88	8,536,499

The following summarizes information about outstanding options at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 1.38 - $ 4.14	6,750	6.4 years	$ 3.72	6,750	$ 3.72
$ 4.15 - $ 6.90	14,850	6.5 years	6.07	14,850	6.07
$ 6.91 - $ 9.66	21,581	7.6 years	7.76	21,581	7.76
$ 9.67 - $13.79	2,918,053	8.1 years	12.13	2,918,053	12.13
$13.80 - $15.25	5,158,316	8.3 years	14.71	5,158,316	14.71
$15.26 - $17.19	723,349	9.7 years	16.90	416,949	16.70
	8,842,899			8,536,499	

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 $7.27 in 2002, $6.51 in 2001 and $5.14 in 2000. Black-Scholes and alternative option-pricing models do not consider the effects of forfeitability and nontransferability on the valuation of employee stock options.

	2002	2001	2000
Risk-free interest rates	3.1%	4.9%	5.8%
Dividend yield	0.2%	0.2%	0.2%
Weighted average expected lives	4 years	4 years	5 years
Volatility	50%	54%	53%

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 2002, 2001 and 2000, 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)	2002	2001	2000
Earnings available to common stock			
As reported	$186,059	$248,816	$115,235
Pro forma	$183,840	$204,543	$ 91,194
Earnings per common share			
Basic As reported	$ 1.12	$ 1.52	$ 0.81
Pro forma	$ 1.10	$ 1.25	$ 0.64
Diluted As reported	$ 1.10	$ 1.50	$ 0.77
Pro forma	$ 1.09	$ 1.23	$ 0.61

13. Acquisitions and Dispositions

Acquisitions

In March 2002, we acquired primarily gas-producing properties for $20 million in the East Texas Freestone Trend. This purchase was funded by bank borrowings. In April 2002, we entered property transactions to increase our positions in East Texas, Louisiana and the San Juan Basin of New Mexico with a total purchase price of $144 million. The transactions, funded by proceeds from our sale of senior notes (Note 3) and subject to typical post-closing adjustments, were as follows:

- A purchase and sale agreement with CMS Oil and Gas Co. (CMS), a subsidiary of CMS Energy Corporation, to acquire properties in the Powder River Basin of Wyoming for $101 million. This acquisition was completed in May 2002.
- An agreement to exchange the Powder River Basin properties acquired from CMS to Marathon Oil Company (Marathon) for primarily gas-producing properties in East Texas and Louisiana. The exchange was completed in May 2002.

- An agreement to purchase primarily gas-producing properties in the San Juan Basin of New Mexico from Marathon for $43 million. This acquisition was completed in July 2002.

In December 2002, we acquired coalbed methane gas-producing properties in the San Juan Basin of southwestern Colorado for $153.8 million from J. M. Huber Corporation. The acquisition was funded through existing bank lines and is subject to typical post-closing adjustments.

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 purchases were funded through bank borrowings.

Acquisitions were recorded using the purchase method of accounting. The following presents unaudited pro forma results of operations for 2002 and 2001, as if these acquisitions had been consummated at the beginning of each period. These pro forma results are not necessarily indicative of future results.

	Pro Forma (Unaudited)	
	Year Ended December 31	
(in thousands, except per share data)	2002	2001
Revenues	$847,988	$932,927
Net income before cumulative effect of accounting change	$187,783	$315,643
Net income	$187,783	$271,054
Earnings per common share:		
Basic	$ 1.13	$ 1.66
Diluted	$ 1.11	$ 1.63
Weighted average shares outstanding	166,700	163,340

In January 2001, we repurchased 9.1 Bcf of natural gas for $9.9 million from a production payment sold to EEX Corporation in a 1998 acquisition. In January 2002, we repurchased an additional 9.2 Bcf of natural gas for $10.8 million. See Note 8.

Dispositions

In June 2001, we filed, with Cross Timbers Royalty Trust, an amended registration statement with the Securities and Exchange Commission to sell 1,360,000 units (22.7% of outstanding units) owned by us. Our sale of these units is dependent upon commodity prices and related market conditions for oil and gas equities. These units are classified as producing properties in the accompanying balance sheet at a net cost of $11.2 million at December 31, 2002. Based on the New York Stock Exchange closing price, these units had a market value of $26.5 million at December 31, 2002.

In March 2000, we sold producing properties in Crockett County, Texas, and Lea County, New Mexico for total gross proceeds of $68.3 million.

In December 1998, we formed the Hugoton Royalty Trust by conveying 80% net profits interests in properties located 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. In 2000, officers exercised options to purchase a total of 1.3 million Hugoton Royalty Trust units from the Company pursuant to the 1998 Royalty Trust Option Plan in exchange for shares of our common stock. We recognized gains of $11 million in 2000 on these sales of trust units.

14. Quarterly Financial Data (Unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2002 and 2001:

(in thousands, except per share data)	Quarter 1st	2nd	3rd	4th
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	$ 0.27	$ 0.21	$ 0.30	$ 0.33
Diluted	$ 0.27	$ 0.21	$ 0.30	$ 0.33
Average shares outstanding	165,094	165,468	167,234	168,957
2001				
Revenues	$249,152	$209,021	$197,307	$183,268
Gross profit [a]	$164,788	$167,514	$129,604	$ 88,269
Net income	$ 46,748	$ 90,533	$ 70,342	$ 41,193
Earnings per common share:				
Basic	$ 0.29	$ 0.55	$ 0.43	$ 0.25
Diluted	$ 0.28	$ 0.54	$ 0.42	$ 0.25
Average shares outstanding	159,520	164,067	164,795	164,892

(a) Operating income before general and administrative expense.

15. 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)	2002	2001	2000
Acquisitions			
Producing properties	$354,110	$238,041	$ 31,983
Undeveloped properties	3,977	3,980	3,490
Development [a]	354,083	385,479	163,224
Exploration			
Geological and geophysical studies	792	2,123	829
Dry hole expense	242	2,189	—
Rental expense and other	1,152	1,126	218
Total	$714,356	$632,938	$199,744

(a) Includes capitalized interest of $4,330,000 in 2002, $6,649,000 in 2001 and $3,488,000 in 2000.

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 or fixed price physical delivery contracts. 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.

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)	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)
PROVED RESERVES			
December 31, 1999	61,603	1,545,623	17,902
Revisions	2,709	142,974	3,709
Extensions, additions and discoveries	1,145	258,843	1,951
Production	(4,736)	(125,857)	(1,622)
Purchases in place	833	26,557	72
Sales in place	(3,109)	(78,457)	—
December 31, 2000	58,445	1,769,683	22,012
Revisions	(4,201)	(96,990)	(2,193)
Extensions, additions and discoveries	3,317	469,602	2,081
Production	(4,978)	(152,178)	(1,601)
Purchases in place	1,484	248,339	—
Sales in place	(18)	(2,978)	—
December 31, 2001	54,049	2,235,478	20,299
Revisions	5,465	76,400	2,433
Extensions, additions and discoveries	1,144	426,541	2,395
Production	(4,757)	(187,583)	(1,850)
Purchases in place	449	330,387	2,156
Sales in place	(1)	(42)	—
December 31, 2002	56,349	2,881,181	25,433
PROVED DEVELOPED RESERVES			
December 31, 1999	48,010	1,225,014	13,781
December 31, 2000	46,334	1,328,953	16,448
December 31, 2001	41,231	1,452,222	14,774
December 31, 2002	47,178	2,042,661	19,367

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

(in thousands)	December 31 2002	2001	2000
Future cash inflows	$14,734,787	$ 6,366,557	$18,866,832
Future costs			
Production	(3,518,614)	(1,989,344)	(3,237,574)
Development	(687,723)	(620,611)	(389,698)
Future net cash flows before income tax	10,528,450	3,756,602	15,239,560
Future income tax	(3,144,235)	(879,874)	(4,947,614)
Future net cash flows	7,384,215	2,876,728	10,291,946
10% annual discount	(3,510,630)	(1,354,679)	(5,029,916)
Standardized measure [a]	$ 3,873,585	$ 1,522,049	$ 5,262,030

(a) Before income tax, the year-end standardized measure (or discounted present value of future net cash flows) was $5,461,298,000 in 2002, $1,947,441,000 in 2001 and $7,748,632,000 in 2000.

Changes in Standardized Measure of Discounted Future Net Cash Flows

(in thousands)	2002	2001	2000
Standardized measure, January 1	$ 1,522,049	$ 5,262,030	$ 1,396,940
Revisions			
Prices and costs	2,554,295	(6,285,062)	5,096,973
Quantity estimates	209,061	173,587	190,457
Accretion of discount	136,924	455,788	123,225
Future development costs	(344,531)	(408,772)	(196,048)
Income tax	(1,122,283)	2,278,522	(2,082,745)
Production rates and other	821	1,090	1,378
Net revisions	1,434,287	(3,784,847)	3,133,240
Extensions, additions and discoveries	632,200	252,524	1,018,349
Production	(610,064)	(653,626)	(441,323)
Development costs	326,219	312,435	128,757
Purchases in place [a]	568,940	148,111	115,866
Sales in place [b]	(46)	(14,578)	(89,799)
Net change	2,351,536	(3,739,981)	3,865,090
Standardized measure, December 31	$ 3,873,585	$ 1,522,049	$ 5,262,030

(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.

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 oil prices used in the estimation of proved reserves and calculation of the standardized measure were $29.69 for 2002, $17.39 for 2001, $25.49 for 2000 and $24.17 for 1999. Year-end average realized gas prices were $4.41 for 2002, $2.36 for 2001, $9.55 for 2000, and $2.20 for 1999. Year-end average realized natural gas liquids prices were $17.86 for 2002, $8.70 for 2001, $26.33 for 2000 and $13.83 for 1999. Proved oil and gas reserves at December 31, 2002 include:

- 1,784,000 Bbls of oil and 206,856,000 Mcf of gas and discounted present value before income tax of $330,746,000 related to our ownership of approximately 54% of Hugoton Royalty Trust units at December 31, 2002.
- 646,000 Bbls of oil and 7,089,000 Mcf of gas and discounted present value before income tax of $18,002,000 related to our ownership of approximately 23% of Cross Timbers Royalty Trust units at December 31, 2002.

Independent Auditors' Reports

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF XTO ENERGY INC.

We have audited the accompanying consolidated balance sheet of XTO Energy Inc. and its subsidiaries as of December 31, 2002, and the related consolidated income statement, statement of cash flows and statement of stockholders' equity for the year then ended. In connection with our audit of the 2002 financial statements, we also have audited the 2002 financial statement schedule. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audit. The 2001 and 2000 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 audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

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

KPMG LLP

Dallas, Texas
March 21, 2003

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.

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
December 31, 2002					
Allowance for doubtful accounts –					
Joint interest and other receivables	$4,098	$ 980	$ (65)	$524	$5,537
December 31, 2001					
Allowance for doubtful accounts –					
Joint interest and other receivables	$3,121	$ 978	$ (1)	$ —	$4,098
December 31, 2000					
Allowance for doubtful accounts –					
Joint interest and other receivables	$2,150	$1,093	$(122)	$ —	$3,121

(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 31st day of March 2003.

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 31st day of March 2003.

Principal Officers (and Directors)

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

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

Directors

By WILLIAM H. ADAMS III
William H. Adams III

By J. LUTHER KING, JR.
J. Luther King, Jr.

By JACK P. RANDALL
Jack P. Randall

By SCOTT G. SHERMAN
Scott G. Sherman

By HERBERT D. SIMONS
Herbert D. Simons

Principal Financial Officer

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

Principal Accounting Officer

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

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-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures 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 as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

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

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003

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-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures 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 as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

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

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003

LOUIS G. BALDWIN

Louis G. Baldwin
Chief Financial Officer

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	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 2012	
4.3	Indenture dated as of October 28, 1997, between the Company and the Bank of New York, as Trustee for the 8¾% Senior Subordinated Notes due 2009 (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-4, File No. 333-39097)	
4.4	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)	
4.5	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)	
10.1*	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)	
10.2*	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)	
10.3*	1998 Stock Incentive Plan, as amended August 20, 2002 (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2002)	
10.4*	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)	
10.5*	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)	

Exhibit No.	Description	Page
10.6*	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)	
10.7*	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)	
10.8*	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)	
10.9*	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)	
10.10*	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)	
10.11*	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)	
10.12*	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)	
10.13*	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)	
10.14	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)	
10.15	Revolving Credit Agreement dated May 12, 2000 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2000)	
10.16	First Amendment, dated June 20, 2000, to Revolving Credit Agreement dated May 12, 2000 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2000)	
10.17	Second Amendment, dated February 16, 2001, to Revolving Credit Agreement dated May 12, 2000 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.15 to Form 10-K for the year ended December 31, 2000)	

Exhibit No.	Description	Page
10.18	Third Amendment, dated May 1, 2001, to Revolving Credit Agreement dated May 12, 2000 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2001)	
10.19	Fourth Amendment, dated May 3, 2002, to Revolving Credit Agreement dated May 12, 2000 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.	
99	Other Exhibits	
	99.1 Chief Executive Officer Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
	99.2 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 St., Suite 2000, Fort Worth, Texas 76102.

directors and officers

DIRECTORS

BOB R. SIMPSON
Chairman and
Chief Executive Officer
XTO Energy Inc.

STEFFEN E. PALKO
Vice Chairman and President
XTO Energy Inc.

WILLIAM H. ADAMS III (b, c)
President
Texas Bank
Fort Worth Downtown

J. LUTHER KING, JR. (a, d)
President
Luther King Capital
Management Corporation

JACK P. RANDALL
President
Randall & Dewey

SCOTT G. SHERMAN (a, b, c)
Owner
Sherman Enterprises

HERBERT D. SIMONS (a, b, c)
Counsel
Winstead Sechrest & Minick P.C.

ADVISORY DIRECTORS

LOUIS G. BALDWIN
Executive Vice President and
Chief Financial Officer
XTO Energy Inc.

DR. LANE G. COLLINS (a, b, c)
Professor of Accounting
Baylor University

KEITH A. HUTTON
Executive Vice President,
Operations
XTO Energy Inc.

VAUGHN O. VENNERBERG II
Executive Vice President,
Administration
XTO Energy Inc.

a) Audit Committee
b) Compensation Committee
c) Corporate Governance and Nominating Committee
d) Mr. King will retire effective May 20, 2003

EXECUTIVE OFFICERS

BOB R. SIMPSON
Chairman and
Chief Executive Officer

STEFFEN E. PALKO
Vice Chairman and President

LOUIS G. BALDWIN
Executive Vice President and
Chief Financial Officer

KEITH A. HUTTON
Executive Vice President,
Operations

VAUGHN O. VENNERBERG II
Executive Vice President,
Administration

SENIOR OFFICERS

NICK J. DUNGEY
Senior Vice President,
Natural Gas Operations

KEN K. KIRBY
Senior Vice President,
Operations
East Texas

BENNIE G. KNIFFEN
Senior Vice President and
Controller

TIMOTHY L. PETRUS
Senior Vice President,
Acquisitions

EDWIN S. RYAN, JR.
Senior Vice President, Land

TERRY L. SCHULTZ
Senior Vice President,
Marketing

KENNETH F. STAAB
Senior Vice President,
Engineering

THOMAS L. VAUGHN
Senior Vice President,
Operations

OTHER OFFICERS

VIRGINIA N. ANDERSON
Vice President and
Corporate Secretary

NINA C. HUTTON
Vice President,
Environmental, Health
and Safety

GARY L. MARKESTAD
Vice President, Operations
San Juan Basin

FRANK G. MCDONALD
Vice President and
General Counsel and
Assistant Secretary

ROBERT C. MYERS
Vice President,
Human Resources

JOHN M. O'REAR
Vice President and Treasurer

F. TERRY PERKINS
Vice President,
Reservoir Engineering

MARK J. POSPISIL
Vice President, Geology and
Geophysics

DOUGLAS C. SCHULTZE
Vice President, Operations
Permian Division

GARY D. SIMPSON
Vice President, Investor
Relations

MARK A. STEVENS
Vice President, Taxation

E. E. STORM III
Vice President and
General Counsel,
Land and Acquisitions

L. FRANK THOMAS III
Vice President,
Information Technology

MICHAEL R. TYSON
Vice President,
Financial Reporting

T. JOY WEBSTER
Vice President, Facilities

ADAM E. AUTEN
Assistant Treasurer

ROBERT B. GATHRIGHT
Assistant Controller and
Director of Budget and
Planning

corporate information

CORPORATE HEADQUARTERS
810 Houston Street
Fort Worth, Texas 76102
(817) 870-2800

OKLAHOMA CITY OFFICE
210 West Park Avenue, Suite 2350
Oklahoma City, Oklahoma 73102
(405) 232-4011

MIDLAND OFFICE
3000 N. Garfield, Suite 175
Midland, Texas 79705
(915) 682-8873

TYLER OFFICE
Woodgate Center
1001 ESE Loop 323, Suite 410
Tyler, Texas 75701
(903) 939-1200

FARMINGTON OFFICE
2700 Farmington Avenue
Bldg. K, Suite 1
Farmington, New Mexico 87401
(505) 324-1090

OZARK OFFICE
P.O. Box 213
1541 Airport Road
Ozark, Arkansas 72949
(479) 667-4819

ALASKA OFFICE
52260 Shell Road
Kenai, Alaska 99611
(907) 776-2511

ANNUAL MEETING
Tuesday, May 20, 2003 at 10 a.m.
Fort Worth Club Tower
777 Taylor Street
12th Floor, Horizon Room
Fort Worth, Texas

INDEPENDENT AUDITORS
KPMG LLP
Dallas, Texas

SENIOR NOTES
7½% Notes due 2012
CUSIP# 98385XAA4

SENIOR SUBORDINATED NOTES
8¾% Notes due 2009
CUSIP# 22757AG7

TRANSFER AGENTS AND REGISTRARS
Common Stock:
Mellon Investor Services LLC
Dallas, Texas
www.mellon-investor.com
Senior Subordinated Notes:
Bank of New York
Corporate Trust Division
New York, New York

FORM 10-K
Additional copies of the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained, without charge, upon request to Investor Relations at our corporate address and are also available free of charge on the Company's web site at www.xtoenergy.com. Copies of any exhibits to the Company's Annual Report on Form 10-K may also be obtained, without charge, upon specific request.

DIRECT STOCK PURCHASE/DIVIDEND REINVESTMENT PLAN
A Direct Stock Purchase and Dividend Reinvestment Plan allows new investors to buy XTO Energy common stock for as little as $500 and existing shareholders to automatically reinvest dividends. For more information, request a prospectus from: Mellon Investor Services LLC at (800) 938-6387.

SHAREHOLDER SERVICES
For questions about dividend checks, electronic payment of dividends, stock certificates, address changes, account balances, transfer procedures and year-end tax information call (888) 877-2892.

WEB SITE
www.xtoenergy.com

GLOSSARY OF TERMS

Bbls	Barrels (of oil or NGLs)
Bcf	Billion cubic feet (of gas)
Bcfe	Billion cubic feet equivalent
BOE	Barrels of oil equivalent
BOPD	Barrels of oil per day
CBM	Coal bed methane
MBO	Thousand barrels of oil
MMBOE	Million barrels of oil equivalent
Mcf	Thousand cubic feet (of gas)
Mcfe	Thousand cubic feet equivalent
MMcf	Million cubic feet (of gas)
MMcfe	Million cubic feet equivalent
NGLs	Natural gas liquids
NPV-10%	Present value of future cash flows discounted at 10%, net of initial investment
ROE	Ratio of net income divided by average stockholders' equity for the period
ROR	Discount rate at which cash flows equals initial investment
Tcfe	Trillion cubic feet equivalent

One barrel of oil is the energy equivalent of six Mcf of natural gas.

ON THE FRONT COVER:

The mechanical fracturing imposed upon tight-rock formations is crucial to providing the conductivity required to economically produce reserves. We design innovative techniques to access trapped natural gas overlooked by others.

COMPANY PROFILE

XTO Energy Inc., established in 1986 as Cross Timbers Oil Company, is a premier domestic natural gas and oil producer engaged in the acquisition and development of high quality legacy properties. The Company operates about 93% of the value of its producing properties, which encompass more than 8,400 oil and gas wells. These properties are concentrated in Texas, New Mexico, Arkansas, Oklahoma, Kansas, Colorado, Wyoming, Alaska and Louisiana.

XTO Energy is listed on the New York Stock Exchange under the symbol "XTO." The Company also created two other publicly traded investments: Cross Timbers Royalty Trust ("CRT" traded on the NYSE) and Hugoton Royalty Trust ("HGT" traded on the NYSE), which went public in 1992 and 1999, respectively.

XTO Energy is headquartered in Fort Worth, Texas. At year-end 2002, the Company had 847 employees.

XTO ENERGY

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Fort Worth, Texas 76102

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