XTO

TO THE CORE

2007

ANNUAL REPORT

XTO ENERGY

XTO ENERGY 2007 ANNUAL REPORT

About Our Annual Report

This year marks a transition in annual reporting. With access of the internet and the abundance of news sources today, more 'real-time' information is immediately available on public companies than ever before. As a result, the SEC is expanding information delivery options to fit the times. Simply put, their mission is to maximize data exposure on public companies and minimize the costs of hard copy printing.

At XTO, we have always taken pride in delivering a high quality Annual Report to our shareholders. Our goal has been to be both timely and comprehensive. In respect of the information delivery transition, this year our report is focused on delivering a poignant message that resonates while being efficient. We invite you to utilize our monthly Investor Presentations, Quarterly Operations Reviews, Press Releases and Analyst Conference materials, along with our 10-K and 10-Q reports, to keep pace with the Company's activities.

At XTO Energy, we look beyond the obvious to unlock value. We defy the conventions for new solutions. We have built success by delivering on our promises.

We're XTO to the core.

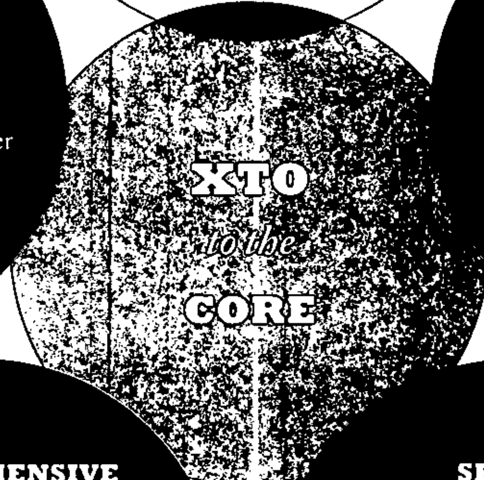

COMMITMENT
EXPERIENCE
STRATEGY
DISCIPLINE
DEDICATION

DELIVERING ON PROMISES

A bond with our shareholders to continue creating value and seeing that value realized in the markets.

STEWARDSHIP AND WISDOM

A management team that has worked together for more than 20 years and has brought together the best seasoned professionals from all disciplines of the industry.



PROVEN PLAN

Acquiring and improving the best properties is the blueprint for consistent growth, superior economic returns and visibility for the future.

COMPREHENSIVE PROCESS

Achieving the maximum productivity from our assets through innovation, technology and operational expertise; no distractions and no compromises.

SPIRIT OF SUCCESS

A talented and unique culture of more than 2,300 strong that works hard, embraces the challenges and thrives on exceptional results.

The core of a wellbore is the rock sample that is cut from the hydrocarbon formation. It helps our geoscientists define the reservoir. It reveals the potential. It portends the prosperity. Like the rock, understanding our core strengths has defined the success of XTO Energy as an investment. Staying focused on the core will deliver the future.

OUR CORE ADVANTAGE:

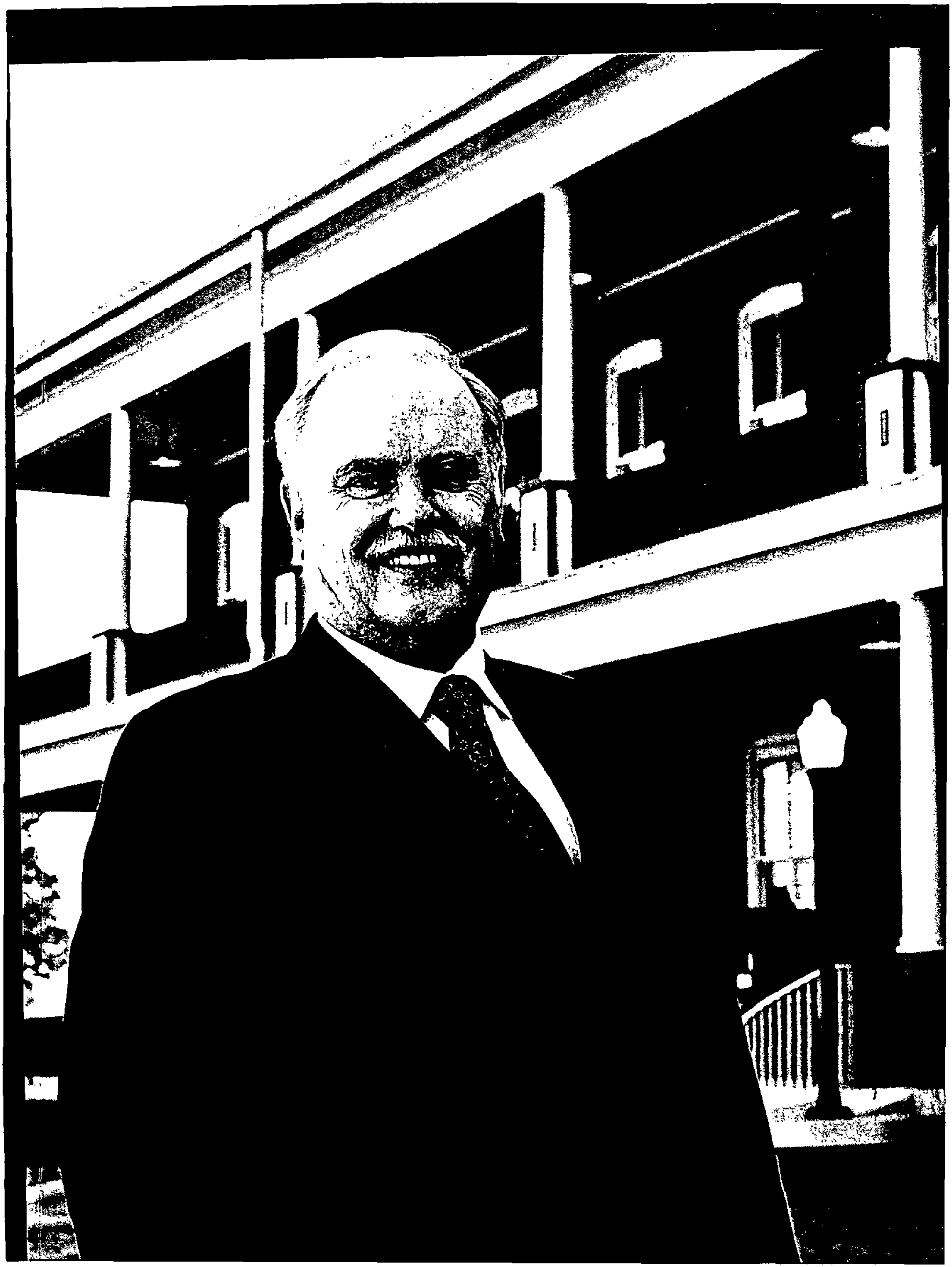
A Solid Investment Designed for Long-Term Rewards

Delivering
A TRACK RECORD OF RECORDS

VALUE WILL PREVAIL. The outstanding performance of XTO, across all industries, reflects this core belief. By demanding both a prolific property portfolio and strong operating margins, our business builds accretive growth in production and reserves, year after year. Our ability to generate free cash flow provides the confidence that XTO Energy will continue to be a leader in growth. Over the long haul, we create value which is the secret to our success.

Stock Up 5679%(1) Since 1993

Compounded Annual Growth of 30%(1) and 24%(1) In Reserves And Production

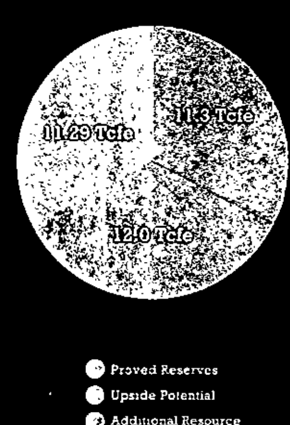


FELLOW SHAREHOLDERS

We enjoyed another exceptional year of performance in 2007 and, as always, it was earned through conviction, determination and hard work. With record activity, our team delivered production growth of 19% and an increase in proved reserves of 32%. The Company achieved record operating cash flow of $3.7 billion, which enabled both a flourishing development campaign and record acquisitions. Along the way, we maintained our discipline in economic efficiency. Simply put, our profit margins remained high, with net income at 31% of revenues, and our costs stayed low, with the drill bit cost to find reserves at $1.64 per Mcfe. As a result, the investment community rewarded our accomplishments by increasing the stock price by 36%. Perhaps even more important to me, as a founder and long-term investor, is that these achievements for the year expanded our potential and added visibility for the future. By sticking to the elements of our core strategy, we did what I believe we do best — create value.

Our value creation process begins with owning the "best rock." These are the most prolific and expansive hydrocarbon reservoirs in the United States. With high-quality, long-lived properties comes upsides in reserve potential, production stability and strong economic margins. This is the basis for our enduring success. For more than 20 years, we have acquired the right assets to build the foundation of XTO Energy; seizing the opportunities as they came available. In 2007, we extended that commitment by purchasing more than $4.0 billion in premier properties that expanded our operating footprint in multiple regions. The marquee acquisition, from Dominion Resources, added about 1 Tcfe of reserves to the Company for $2.5 billion. These properties substantially increased our holdings in the Rocky Mountains and interior South Texas and contain abundant upsides. By applying our tight-gas and coal bed methane expertise, our teams are planning long-term growth platforms from both areas. Also, we significantly increased our positions in the Barnett, Fayetteville and Woodford shale plays, along with securing "bolt on" properties in East Texas and our legacy fields of the San Juan and Permian basins. These resource-rich assets provide a fresh opportunity for our team to discover new production and reserves.

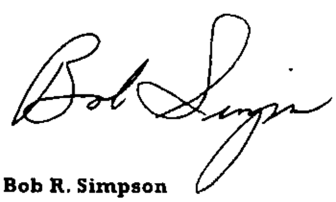
CAPTURED RESOURCES 2008
(estimated in Tcfe)



Given the hand-picked acquisitions and our development efforts, the Company's growth regions continue to expand at a fast pace. As depicted in the pie chart, proved reserves now total 11.29 Tcfe, but captured potential is twice as large. Of this potential, our engineers have nominated 11.3 Tcfe of upsides for visible future growth. The East Texas region, where XTO is the leading natural gas producer, will continue to lead the charge. After a decade of volume increases, the Freestone Trend still contains thousands of new well locations, representing 4.3 Tcfe of potential. Advanced drilling and completion techniques continue to unlock more resource. The burgeoning shale plays have now arrived as a powerful component of our future plans. In the Barnett Shale, where XTO has grown net daily production from about 100 MMcf to 500 MMcf in just two years, we recognize another 4.2 Tcfe of potential to exploit. In the Fayetteville and Woodford shale plays, our teams have expanded the leasehold positions to 240,000 and 120,000 net acres, respectively. Our drilling inventory in these plays reflects 3.6 Tcfe of potential. In total, the captured resource for the Company improved by more than 37% over the past year and represent more than five years of drilling inventory. By understanding the productive characteristics of this inventory and our overall production profile, we can schedule future growth with confidence.

Understanding the commodity price environment is critical to realizing the extraordinary value which is captured in XTO. From our perspective, the outlook for oil and natural gas appears to be entrenched in the "stronger for longer" cycle, which we correctly identified in 2003. In spite of a slowing global economy, the challenge to supply the world's growing appetite for crude remains difficult. New production sources are struggling to overcome the natural declines of the giant old fields. Thus, high oil prices are a necessity to moderate consumption. In the domestic natural gas arena, doubling the drilling rig count in the last five years has only modestly grown production. When combined with the trend of warmer winters, this clean-burning commodity has been priced at a discount relative to its inherent value. However, the ambition to grow natural gas production, with only minimal effect, has forced a steep underlying production decline that will become more difficult to overcome. At the same time, new power generation is driving additional demand. In our view, the pressure on natural gas prices is biased towards the upside. As a result, companies with increasing reserves and production, like XTO, should be well positioned for prosperity.

Moving ahead, our Company is poised for another record year in 2008. Plans already target 20% production growth. With about 65% of our production hedged, record cash flow should be available to fund our development growth and "bolt on" acquisitions. Even as we get bigger, we are maintaining the same discipline that has delivered growth and created value since inception. Our dedicated team is forging ahead, executing with passion and pursuing the best performance … that's our core culture at XTO Energy.



Bob R. Simpson
Chairman and Chief Executive Officer

SELECTED HIGHLIGHTS

	2007	2006	2005	2004	2003
FINANCIAL (in millions, except per share data)					
Total revenues	$ 5,513	$ 4,576	$ 3,519	$ 1,948	$ 1,189
Operating income	$ 2,892	$ 2,672	$ 1,963	$ 919	$ 502
Net income	$ 1,691[a]	$ 1,860[b]	$ 1,152[c]	$ 508[d]	$ 288[e]
Earnings per common share[f]					
Basic	$ 3.58	$ 4.08	$ 2.57	$ 1.22	$ 0.77[g]
Diluted	$ 3.53	$ 4.02	$ 2.52	$ 1.21	$ 0.76[g]
Operating cash flow[h]	$ 3,742	$ 3,078	$ 2,276	$ 1,286	$ 792
Total assets	$ 18,922	$ 12,885	$ 9,857	$ 6,110	$ 3,611
Long-term debt	$ 6,320	$ 3,451	$ 3,109	$ 2,043	$ 1,252
Total stockholders' equity	$ 7,941	$ 5,865	$ 4,209	$ 2,599	$ 1,466
Common shares outstanding at year-end[f]	485.3	459.4	454.5	434.0	390.4
PRODUCTION (in thousands, except per unit data)					
Average daily production					
Gas (Mcf)	1,457.8	1,186.3	1,033.1	834.6	668.4
Natural gas liquids (Bbl)	13.5	11.9	10.4	7.5	6.5
Oil (Bbl)	47.1	45.0	39.1	22.7	12.9
Mcfe	1,821.4	1,527.7	1,330.1	1,015.7	784.9
Average sales price					
Gas (per Mcf)	$ 7.50	$ 7.69	$ 7.04	$ 5.04	$ 4.07
Natural gas liquids (per Bbl)	$ 45.37	$ 37.03	$ 34.10	$ 26.44	$ 19.99
Oil (per Bbl)	$ 70.08	$ 60.96	$ 47.03	$ 38.38	$ 28.59
PROVED RESERVES (in millions)					
Gas (Mcf)	9,441.1	6,944.2	6,085.6	4,714.5	3,644.2
Natural gas liquids (Bbl)	66.8	53.0	47.4	38.5	34.7
Oil (Bbl)	241.2	214.4	208.7	152.5	55.4
Mcfe	11,289.0	8,548.6	7,622.2	5,860.3	4,184.9
STOCK PRICES[f]					
High	$ 53.66	$ 40.48	$ 36.13	$ 20.97	$ 13.46
Low	$ 35.48	$ 29.58	$ 18.42	$ 12.01	$ 8.02
Close	$ 51.36	$ 37.64	$ 33.80	$ 20.41	$ 13.06
Cash dividends per share	$ 0.408	$ 0.252[i]	$ 0.180	$ 0.072	$ 0.019[j]
Average daily trading volume (in thousands)	4,730	4,758	4,503	3,295	2,396

a) Includes pre-tax effects of a $43 million non-cash derivative fair value loss.

b) Includes pre-tax effects of a gain on the distribution of Hugoton Royalty Trust units of $469 million, income tax expense related to enactment of a new State of Texas margin tax of $34 million and a $39 million non-cash derivative fair value gain.

c) Includes pre-tax effects of a $39 million non-cash derivative fair value gain, non-cash performance award compensation of $34 million, and a gain of $10 million on the exchange of producing properties

d) Includes pre-tax effects of a $6 million non-cash derivative fair value loss, stock-based incentive compensation of $89 million and special bonuses totaling $12 million related to the ChevronTexaco and ExxonMobil acquisitions. Stock-based incentive compensation includes cash compensation of $22 million related to cash-equivalent performance shares

e) Includes pre-tax effects of a $10 million non-cash derivative fair value loss, a non-cash contingency gain of $2 million, non-cash performance award compensation of $53 million, a $10 million loss on extinguishment of debt, a $16 million non-cash gain on the distribution of Cross Timbers Royalty Trust units, and a $2 million after-tax gain on adoption of the accounting standard for asset retirement obligation.

f) Adjusted for the four-for-three stock split effected on March 18, 2003, the five-for-four stock split effected on March 17, 2004, the four-for-three stock split effected on March 15, 2005 and the five-for-four stock split effected on December 13, 2007

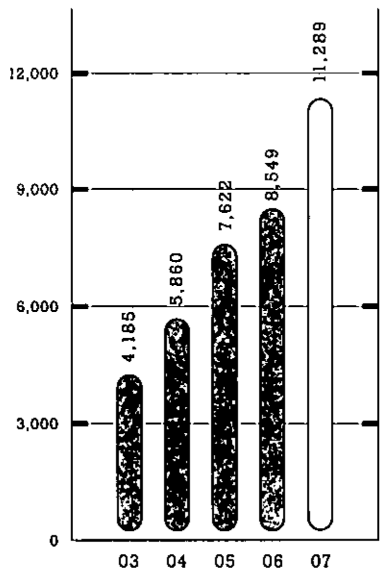
g) Before cumulative effect of accounting change, earnings per share were $0.76 basic and $0.75 diluted.

h) Defined as cash provided by operating activities before changes in operating assets and liabilities and exploration expense and significant cash flow effects of unusual and infrequently occurring items. See Non-GAAP Measures on page 80.

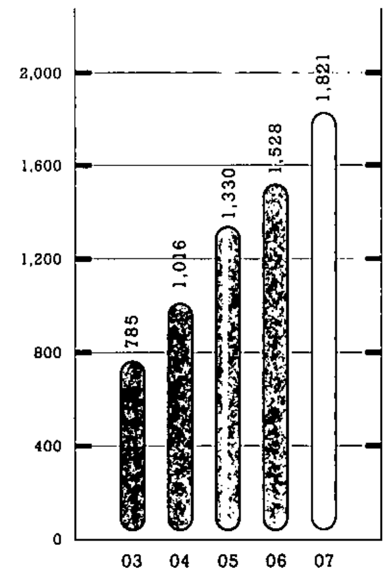
i) Excludes the May 2006 distribution of all of the Hugoton Royalty Trust units owned by the Company to its stockholders as a dividend with a market value of approximately $1.35 per common share.

j) Excludes the September 2003 distribution of all of the Cross Timbers Royalty Trust units owned by the Company to its stockholders as a dividend with a market value of approximately $0.07 per common share

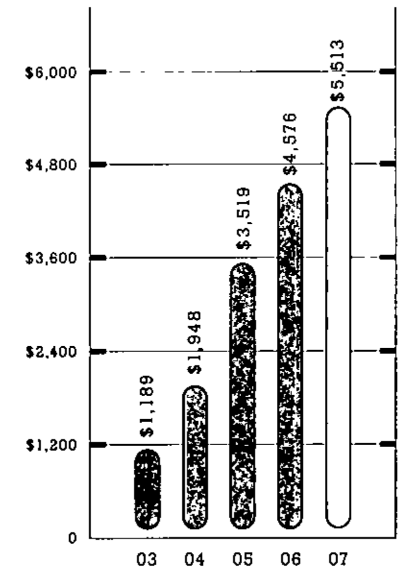
PROVED
RESERVES
(in Bcfe)



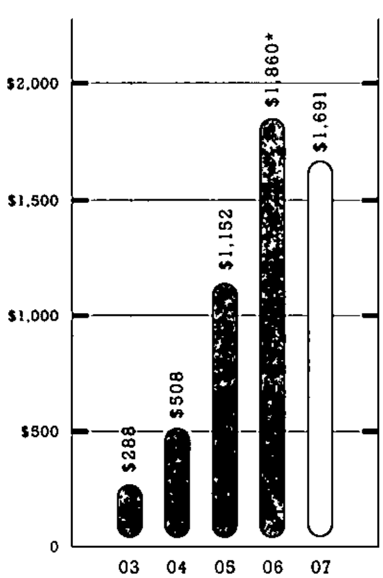
DAILY
PRODUCTION
(in MMcfe)



TOTAL
REVENUE
(in millions)

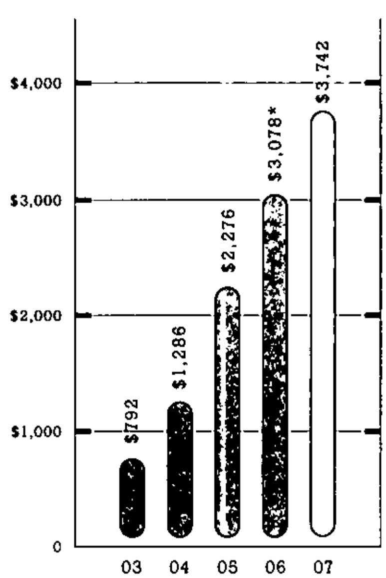


NET
INCOME
(in millions)



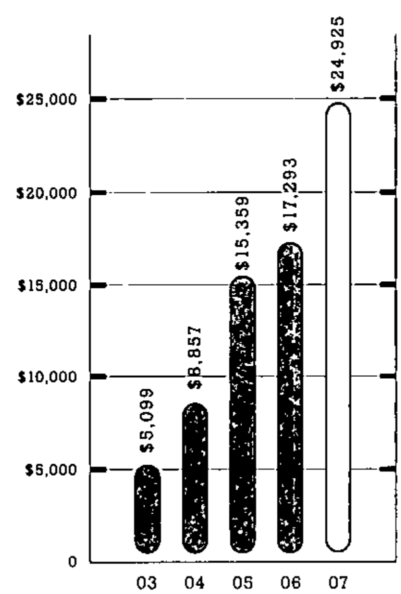
** Includes $295 million after-tax gain on the distribution of Hugoton Royalty Trust units.*

OPERATING
CASH FLOW
(in millions)



** Excludes $211 million of current taxes related to gain on the distribution of Hugoton Royalty Trust units.*

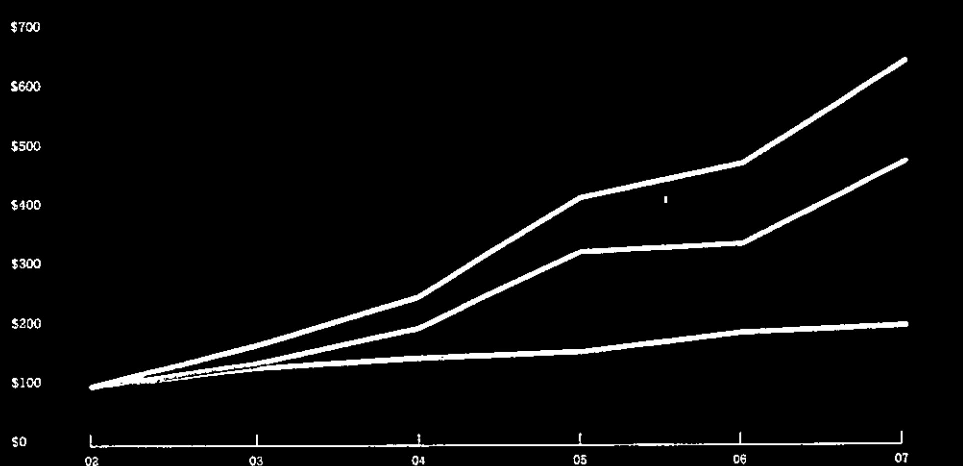
MARKET
CAPITALIZATION
(in millions)



The following graph compares the cumulative 5-year total return to shareholders on XTO Energy Inc.'s common stock relative to the cumulative 5-year total returns of the S&P 500 Index and the Dow Jones US Exploration & Production Index from December 31, 2002 through December 31, 2007. The graph assumes that the value of the investment in the company's common stock and in each of the indexes was $100 on 12/31/2002 and that all dividends were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

(Among XTO Energy Inc., The S&P 500 Index and The Dow Jones US Exploration & Production Index)



XTO Energy Inc.
The Dow Jones US Exploration & Production
The S&P 500

$100 [illegible]
of dividends. Fiscal year ending December 31

The following table sets forth quarterly high and low closing prices for each quarter of 2007 and 2006, as adjusted for the effect of the five-for-four stock split effected in December 2007 and the May 2006 distribution of Hugoton Royalty Trust units.

XTO ENERGY - NYSE	HIGH	LOW
Year ended december 31, 2007		
First quarter	$ 44.46	$ 35.48
Second quarter	50.82	43.42
Third quarter	50.37	41.98
Fourth quarter	53.66	48.50
Year ended december 31, 2006		
First quarter	$ 38.04	$ 30.80
Second quarter	36.91	29.56
Third quarter	38.68	31.52
Fourth quarter	40.48	32.00

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, 2007

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________
Commission File Number: 1-10662

XTO ENERGY INC.

(Exact name of registrant as specified in its charter)

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

Registrant's telephone number, including area code (817) 870-2800
Securities registered pursuant to Section 12(b) of the Act:

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

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

Large accelerated filer ☒ Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if smaller reporting company) Smaller reporting company ☐

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

As of June 29, 2007, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $22.0 billion based on the closing price as reported on the New York Stock Exchange.

Number of Shares of Common Stock outstanding as of February 21, 2008 — 510,323,631

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 29, 2008.

XTO ENERGY INC.

2007

ANNUAL REPORT ON FORM 10-K

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Business and Properties

GENERAL

XTO Energy Inc. and its subsidiaries ("the Company") 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.

All common stock shares and per share amounts in this Form 10-K have been restated for the effect of the five-for-four stock split effected December 13, 2007.

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 through acquisition of proved oil and gas reserves and unproved properties, development and exploitation activities and purchases of additional interests in or near our acquired properties. We expect growth in the immediate future to continue to be accomplished through a combination of acquisitions and development. During 2008, we plan to continue to review acquisition opportunities including property divestitures by major energy related companies, public exploration and development companies and private energy companies. Completion of additional acquisitions will depend on the quality of properties available, commodity prices and competitive factors.

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 an extensive base of hydrocarbons in place and well-established production histories concentrated in the following areas:

- Eastern Region, including the East Texas Basin, northwestern Louisiana and Mississippi;
- North Texas Region, including the Barnett Shale;
- San Juan Region;
- Permian and South Texas Region; and
- Mid-Continent and Rocky Mountain Region, including the Fayetteville and Woodford Shales.

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, or natural gas converted to Bbls, 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 of natural gas equivalent
- BOE — Barrels of oil equivalent
- Mcf — Thousand cubic feet (of natural gas)
- Mcfe — Thousand cubic feet of natural gas 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, 2007 were 9.44 Tcf of natural gas, 67 million Bbls of natural gas liquids and 241 million Bbls of oil, based on December 31, 2007 prices of $6.39 per Mcf for gas, $60.24 per Bbl for natural gas liquids and $91.19 per Bbl for oil. On an energy equivalent basis, our proved reserves were 11.29 Tcfe at December 31, 2007, a 32% increase from proved reserves of 8.55 Tcfe at the prior year end. Increased proved reserves during 2007 were primarily the result of development and exploitation activities and acquisitions. On an Mcfe basis, 66% of proved reserves were proved developed reserves at December 31, 2007. During 2007, our average daily production was 1.46 Bcf of gas, 13,545 Bbls of natural gas liquids and 47,047 Bbls of oil. Fourth quarter 2007 average daily production was 1.67 Bcf of gas, 14,462 Bbls of natural gas liquids and 48,844 Bbls of oil.

of our proved reserves is 16.3 years. The projected 2008 production is from proved developed producing reserves as of December 31, 2007. In general, our properties have extensive production histories and production enhancement opportunities. Within each of our geographical regions, we have one or more core areas in which our major producing fields are concentrated. For example, the core area in the North Texas region is the Barnett Shale. This allows for substantial economies of scale in production and cost-effective application of reservoir management techniques gained from prior operations. As of December 31, 2007, we owned interests in 25,163 gross (13,403.8 net) producing wells, and we operated wells representing 88% 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 a substantial inventory of between 9,500 and 10,300 identified potential drilling locations. Of these locations, approximately 3,100 have proved undeveloped reserves attributed to them. Drilling plans are primarily dependent upon product prices, the availability and pricing of drilling equipment and supplies, and gathering, processing and transmission infrastructure.

We employ a disciplined acquisition program refined by senior management to expand our reserve base in core areas and to add new core areas. 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 geologic and reservoir characteristics. The Company then uses its development and technology knowledge to increase the reserves of acquired properties.

We operate gas gathering systems in several of our core producing areas. We also operate gas processing plants in Texas County, Oklahoma and the Cotton Valley Field of Louisiana. Our gas gathering and processing operations are only in areas where we have production and are considered activities that facilitate our natural gas production and sales operations.

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

HISTORY OF THE COMPANY

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

During 1991, we formed Cross Timbers Royalty Trust by conveying a 90% net profits interest in substantially all of the royalty and overriding royalty interests that we then owned in Texas, New Mexico and Oklahoma, and a 75% net profits interest in seven nonoperated working interest properties in Texas and Oklahoma. Cross Timbers Royalty Trust units are listed on the New York Stock Exchange under the symbol "CRT." From 1996 to 1998, we purchased 1,360,000, or 22.7%, of the outstanding units, at a total cost of $18.7 million. In August 2003, the Board of Directors declared a dividend of 0.0036 units of the trust for each share of our common stock outstanding on September 2, 2003. As a result of this dividend, all of the 1,360,000 trust units were distributed on September 18, 2003.

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. Hugoton Royalty Trust units are listed on the New York Stock Exchange under the symbol "HGT." We sold 17 million units in the trust's initial public offering in 1999 and issued 1.3 million units pursuant to an employee incentive plan in 1999 and 2000. In January 2006, the Board of Directors declared a dividend of 0.047688 trust units for each share of our common stock outstanding on April 26, 2006. As a result of this dividend, all of the remaining 21.7 million trust units were distributed on May 12, 2006.

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. Natural gas prices are generally determined by North American supply and demand and are increasingly being affected by imports of liquefied natural gas. Weather has a significant impact on demand for natural gas since it is a primary heating resource. Its increased use for electrical generation has kept natural gas demand elevated throughout the year, removing some of the seasonal swing in prices. See "Significant Events, Transactions and Conditions — Product Prices" in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, regarding recent price fluctuations and their effect on our results.

The primary components of our business strategy are:

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

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

- contain complex, multiple-producing horizons with the potential for increases in reserves and production,
- produce from nonconventional sources, including tight natural gas reservoirs, coal bed methane and natural gas-producing shale formations,
- are in core operating areas or in areas with similar geologic and reservoir characteristics, and
- provide opportunities to improve operating efficiencies.

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. Our ability to successfully purchase properties is dependent upon, among other things, competition for such purchases and the availability of financing to supplement internally generated cash flow.

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

Increasing Production and Reserves. A principal component of our strategy is to increase production and reserves through aggressive management of operations and low-risk development. We believe that our principal properties possess geologic and reservoir characteristics that make them well suited for production increases through drilling and other development programs. 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 2008, 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 $125 million of our $2.6 billion 2008 development budget for exploration activities.

Hedging Activities. To reduce production price risk, we may enter futures contracts, collars and price and basis swap agreements, as well as fixed price physical delivery contracts. Our policy is to consider hedging a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the full 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 help assure the economic return on acquisitions,
- 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, a founder, Chairman and Chief Executive Officer of the Company, was previously an executive officer of Southland Royalty Company, one of the largest U.S. independent oil and gas producers prior to its acquisition by Burlington Northern, Inc. in 1985.

Other Strategies. We may also acquire working interests in nonoperated producing properties if such interests otherwise meet our acquisition criteria. We attempt to acquire nonoperated interests in fields where the operators have a significant interest to

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

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

Business Goals. In February 2008, we announced a strategic goal for 2008 of increasing production by 20% over 2007 levels and to increase proved reserves to 15 Tcfe by December 31, 2009. To achieve these growth targets, we plan to drill about 1,160 (980 net) development wells and perform approximately 750 (600 net) workovers and recompletions in 2008. No development budget has been announced for 2009.

We have budgeted $2.6 billion for our 2008 development program, which is expected to be funded by cash flow from operations. We plan to spend approximately $850 million in the Eastern Region, $700 million in the North Texas Region, $425 million in the Permian and South Texas Region, $300 million in the San Juan Region and $200 million in the Mid-Continent and Rocky Mountain Region and other areas and approximately $125 million for exploration activities. An additional $400 million has been budgeted for the construction of pipeline infrastructure and compression and processing facilities that are critical to the transportation and sale of production in several operating regions.

While an acquisition budget has not been formalized, we expect to complete acquisitions of both producing and unproved properties for approximately $1.0 billion, during the first quarter of 2008. These acquisitions will be funded both by commercial paper borrowings and by proceeds from the February 2008 common stock offering and are subject to typical post-closing adjustments. We plan to actively review additional acquisition opportunities during 2008. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, our commercial paper program, issuance of public or private debt or equity, or asset sales. Strategic property acquisitions during 2008 may alter the amount currently budgeted for development and exploration. Our total budget for acquisitions, development and exploration will be adjusted throughout 2008 to focus on opportunities offering the highest rates of return. We also may reevaluate our budget and drilling programs in the event of significant changes in oil and gas prices or additional acquisitions. Our ability to achieve production goals depends on the success of our planned drilling programs or property acquisitions made in place of a portion of the drilling program.

Continued raw material shortages and strong global demand for steel have caused prices to remain high. In response, we have maintained a higher tubular inventory and have negotiated supply contracts with our suppliers to support our development program. While we expect to acquire adequate supplies to complete our development program, a further tightening of steel supplies could restrain the program, limiting production growth and increasing development costs.

Although drilling rigs have been in short supply throughout the industry, we have secured or contracted to secure the rigs necessary to support our current drilling program.

ACQUISITIONS

During 2003, we acquired predominantly gas-producing properties for a total cost of $624 million. In April 2003, we acquired natural gas and coal bed methane producing properties in the Raton Basin of Colorado, the Hugoton Field of southwestern Kansas and the San Juan Basin of New Mexico and Colorado for $381 million from Williams of Tulsa, Oklahoma. In June 2003, we acquired coal bed methane and gas-producing properties in the San Juan Basin of New Mexico and Colorado from Markwest Hydrocarbon, Inc. for $51 million. In October 2003, we announced the completion of property transactions which increased our positions in East Texas, Arkansas and the San Juan Basin of New Mexico for a total cost of $100 million. The 2003 acquisitions increased reserves by approximately 465.7 Bcf of natural gas, 4.5 million Bbls of natural gas liquids and 2.2 million Bbls of oil.

During 2004, we acquired proved properties for a total cost of $1.9 billion. In January 2004, we acquired proved properties in East Texas and northwestern Louisiana for $243 million from multiple parties. From February through April, we purchased $223 million of properties located primarily in the Barnett Shale of North Texas and in the Arkoma Basin. Two of these acquisitions were purchases of corporations that primarily owned producing and nonproducing properties. Purchase accounting adjustments related to these acquisitions included a $72 million deferred income tax step-up adjustment. During April, we acquired predominantly oil-producing properties in the Permian Basin of West Texas and gas-producing properties in the Powder River Basin of Wyoming from ExxonMobil Corporation for $336 million. In August, we acquired properties from ChevronTexaco Corporation for a purchase price of $958 million, as adjusted for subsequent purchase of properties that were subject to preferential purchase rights. These properties expanded our operations in our Eastern Region, the Permian Basin and the Mid-Continent Region and added new coal bed methane properties in the Rocky Mountains and new properties in South Texas. Our 2004 acquisitions increased reserves by approximately 716.5 Bcf of natural gas, 2.9 million Bbls of natural gas liquids and 98.2 million Bbls of oil.

million of debt assumed, $225 million recorded on the step-up of deferred taxes and the assumption of other liabilities, the total purchase price plus liabilities assumed was $1.26 billion. This amount was allocated to assets acquired including approximately $634 million to proved properties, $180 million to unproved properties, $175 million to acquired gas gathering contracts and related gas gathering and pipeline assets, $215 million to goodwill and $57 million to other assets. In May, we acquired proved properties in East Texas and northwestern Louisiana from Plains Exploration & Production Company for an adjusted purchase price of $336 million. In July 2005, we acquired proved properties in the Permian Basin of West Texas and New Mexico from ExxonMobil Corporation for an adjusted purchase price of $200 million. Our 2005 acquisitions increased reserves by approximately 803.4 Bcf of natural gas, 2.8 million Bbls of natural gas liquids and 31.1 million Bbls of oil.

During 2006, we acquired proved properties for a total cost of $561 million. In February 2006, we acquired proved and unproved properties in East Texas and Mississippi from Total E&P USA, Inc. for $300 million. In June 2006, we acquired Peak Energy Resources, Inc., which operated gas-producing properties and owned unproved properties in the Barnett Shale in the Fort Worth Basin. The purchase price was $108 million, which was primarily funded by issuance of 3.2 million shares of common stock valued at $102 million, $5 million cash for additional leasehold interests and $1 million cash for other transaction costs. After recording estimated deferred taxes of $36 million and other liabilities, the purchase price allocated to proved properties was $97 million and unproved properties was $53 million. Our 2006 acquisitions increased reserves by approximately 157.9 Bcf of natural gas, 4.2 million Bbls of natural gas liquids and 3.3 million Bbls of oil.

During 2007, we acquired proved reserves for a total of $3.2 billion. We also acquired $831 million of unproved properties in 2007. In July 2007, we acquired both producing and unproved properties from Dominion Resources, Inc. for $2.5 billion, subject to typical post-closing adjustments. These properties are located in the Rocky Mountain Region, the San Juan Basin and South Texas. The acquisition was funded by the issuance of 21.6 million shares of our common stock in June 2007 for net proceeds of $1.0 billion, the issuance of $1.25 billion of senior notes in July 2007 and with borrowings under our commercial paper program, which was repaid with a portion of the proceeds from the issuance of $1.0 billion of senior notes in August 2007. After recording an asset retirement obligation of $32 million, other liabilities and transaction costs of $18 million, the purchase price allocated to proved properties was $2.5 billion and unproved properties was $73 million. In October 2007, we announced acquisitions from multiple parties of both producing and unproved properties in the Barnett Shale for approximately $550 million. All 2007 acquisitions are subject to typical post-closing adjustments. Our 2007 acquisitions increased reserves by approximately 1.3 Tcf of natural gas, 2.7 million Bbls of natural gas liquids and 11.3 million Bbls of oil.

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, 2007:

(in millions)	Proved Reserves: Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)	Natural Gas Equivalents (Mcfe)	Discounted Present Value before Income Tax of Proved Reserves (a)	
Eastern Region	3,861.1	15.8	11.8	4,026.8	$ 9,242	32%
North Texas Region	2,288.6	6.3	–	2,326.4	4,501	15%
San Juan Region	1,129.1	42.5	2.2	1,397.3	3,164	11%
Permian and South Texas Region	560.2	2.2	192.4	1,728.0	8,127	28%
Mid-Continent and Rocky Mountain Region	1,598.8	–	18.5	1,709.3	3,681	13%
Other	3.3	–	16.3	101.2	454	1%
Total	9,441.1	66.8	241.2	11,289.0	$ 29,169	100%

(a) We believe that the discounted present value of estimated future net cash flows before income tax is a useful supplemental disclosure to the standardized measure, or after-tax amount, of $19.5 billion. While the standardized measure is dependent on the unique tax situation of each company, the pre-tax discounted amount is based on prices and discount factors that are consistent for all companies. Because of this, the pre-tax discounted amount can be used within the industry and by securities analysts to evaluate estimated future net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the pre-tax discounted amount is the discounted estimated future income tax of $9.6 billion at December 31, 2007.

Eastern Region

We began operations in East Texas and northwestern Louisiana in 1998. These properties produce from various formations at depths between 7,000 feet and 14,000 feet. Subsequent acquisitions and development activity have significantly increased reserves here since we began operations, and we now own an interest in approximately 690,000 net acres. Over 35% of our total proved reserves are in this region. We have 2,650 to 2,950 identified potential drilling locations in this area. In 2005, we expanded our gathering facilities to increase treating capacity to 730,000 Mcf per day. An additional 330,000 Mcf per day of treating capacity is expected to be completed in mid 2008. In 2008, we plan to drill between 340 and 380 wells in the Eastern Region.

gas development area in 2007. Other areas in the region include the Sabine Uplift and Cotton Valley areas of East Texas and northwestern Louisiana.

North Texas Region

Our operations in the Barnett Shale of North Texas began in January 2004 and, with our 2005 acquisition of Antero Resources Corporation, 2006 acquisition of Peak Energy Resources and various 2007 acquisitions, we are one of the largest producers in the area. We own approximately 250,000 net acres, 50% of which is in the core productive area, 841 producing wells and gas gathering and pipeline assets. We have 2,200 to 2,300 identified potential drilling locations in this area and plan to drill approximately 250 to 300 wells in 2008. We also own 225,000 Mcf per day of treating capacity allowing us to add new wells as they are completed. An additional 330,000 Mcf per day of treating capacity is expected to be completed during second quarter 2008.

San Juan Region

Our San Juan Region includes properties in the San Juan and Raton Basins of New Mexico and Colorado, as well as properties in the Uinta Basin of Utah. As a result of the 2007 Dominion acquisition, we significantly expanded our holdings in the Uinta Basin. Production is from conventional as well as coal bed methane sources. We have 1,500 to 1,600 identified potential drilling locations to develop these complex, multi-pay basins. In 2005, we entered a new tight-gas play in the Piceance Basin of Colorado through a farmout agreement with ExxonMobil, and in 2007 we completed the final well of a four-well commitment.

Permian and South Texas Region

The Permian and South Texas Region is made up of properties in West Texas, southeastern New Mexico and South Texas. In 2004, 2005 and 2007, we significantly expanded our holdings in the area through acquisitions and trades with ChevronTexaco, ExxonMobil, ConocoPhillips, Dominion and others. Our activities on these properties have increased oil production by returning shut-in wells to production, optimizing existing well performance, using fracture stimulation and drilling. We have also experienced successful results in multiple fields including Yates, University Block 9, Goldsmith, Russell, Prentice and Cornell. We have 1,250 to 1,350 identified potential drilling locations in this area.

Mid-Continent and Rocky Mountain Region

Our Mid-Continent and Rocky Mountain Region includes fields in Wyoming, Montana, Kansas, Oklahoma and Arkansas. We have operations in the Anadarko Basin, Fontenelle area, Powder River Basin and the Arkoma Basin. During 2008, we plan to continue drilling activities in the Fayetteville Shale in Arkansas and the Woodford Shale in Southeast Oklahoma. While most of our production in the region is from conventional sources, we are developing coal bed methane in the Powder River Basin of Wyoming. We have 1,900 to 2,100 identified potential drilling locations in this area. A portion of our properties in the Mid-Continent Region are subject to an 80% net profits interest conveyed to the Hugoton Royalty Trust in December 1998.

We operate a gathering system and pipeline in Major County, Oklahoma and a gas plant in Texas County, Oklahoma, and its associated gathering system. We also completed a gas gathering and water disposal system in the Hartzog Draw area of Wyoming to service our coal bed methane wells.

RESERVES

The following terms are used in our disclosures of oil and natural gas reserves. For the complete detailed definitions of proved, proved developed and proved undeveloped oil and gas reserves applicable to oil and gas registrants, reference is made to Rule 4-10(a)(2)(3)(4) of Regulation S-X of the Securities and Exchange Commission, available at its web site http://www.sec.gov/about/forms/regs-x.pdf.

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

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

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

Estimated future net revenues — Also referred to herein as "estimated future net cash flows." Computational result of applying current prices of oil and gas (with consideration of price changes only to the extent provided by existing contractual arrangements, other

Present value of estimated future net cash flows — The computational result of discounting estimated future net revenues at a rate of 10% annually. The present value of estimated future net cash flows after income tax is also referred to herein as "standardized measure of discounted future net cash flows" or "standardized measure."

The following are estimated quantities of proved reserves and related cash flows as of December 31, 2007, 2006 and 2005:

	December 31		
(in millions)	2007	2006	2005
Proved developed:			
Gas (Mcf)	6,031.5	4,481.6	4,033.1
Natural gas liquids (Bbls)	52.9	40.1	36.5
Oil (Bbls)	184.8	167.3	168.5
Mcfe	7,457.7	5,725.9	5,262.9
Proved undeveloped:			
Gas (Mcf)	3,409.6	2,462.6	2,052.5
Natural gas liquids (Bbls)	13.9	12.9	10.9
Oil (Bbls)	56.4	47.1	40.2
Mcfe	3,831.3	2,822.7	2,359.3
Total proved:			
Gas (Mcf)	9,441.1	6,944.2	6,085.6
Natural gas liquids (Bbls)	66.8	53.0	47.4
Oil (Bbls)	241.2	214.4	208.7
Mcfe	11,289.0	8,548.6	7,622.2
Estimated future net cash flows:			
Before income tax (a)	$ 57,949	$ 32,259	$ 50,897
After income tax	$ 39,526	$ 22,008	$ 34,074
Present value of estimated future net cash flows, discounted at 10%:			
Before income tax (a)	$ 29,169	$ 16,228	$ 25,816
After income tax	$ 19,538	$ 10,828	$ 17,094

(a) We believe that the estimated future net cash flows before income tax and the discounted present value of estimated future net cash flows before income tax are useful supplemental disclosures to the after-tax estimated future net cash flows and the standardized measure, or after-tax amount. While the after-tax estimated future net cash flows and the standardized measure are dependent on the unique tax situation of each company, the pre-tax measures are based on prices and discount factors that are consistent for all companies. Because of this, the pre-tax measures can be used within the industry and by securities analysts to evaluate estimated future net cash flows from proved reserves on a more comparable basis. The difference between the after-tax and the pre-tax estimates of future net cash flows is estimated future income tax of $18.4 billion at December 31, 2007, $10.3 billion at December 31, 2006 and $16.8 billion at December 31, 2005. The difference between the standardized measure and the pre-tax discounted amount is the discounted estimated future income tax of $9.6 billion at December 31, 2007, $5.4 billion at December 31, 2006 and $8.7 billion at December 31, 2005.

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, 2007, 2006 and 2005. 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. None of our natural gas liquid proved reserves are attributable to gas plant ownership.

Estimated future net cash flows, and the related 10% discounted present value, of year-end 2007 proved reserves are significantly higher than at year-end 2006 because of higher commodity prices used in estimation of year-end proved reserves and increased reserves related to development and acquisitions. Year-end 2007 average realized prices used in the estimation of proved reserves were $6.39 per Mcf for gas, $60.24 per Bbl for natural gas liquids and $91.19 per Bbl for oil. Year-end 2006 product prices were $5.46 per Mcf for gas, $31.96 per Bbl for natural gas liquids and $55.47 per Bbl for oil. See Note 15 to Consolidated Financial Statements for additional information regarding estimated proved reserves.

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 2007, we filed estimates of oil and gas reserves as of December 31, 2006 with the U.S. Department of Energy on Form EIA-23 and Form EIA-28. These estimates are consistent with the reserve data reported for the year ended December 31, 2006 in Note 15 to Consolidated Financial Statements, with the exception that Form EIA-23 includes only reserves from properties that we operate.

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, 2007, all of which are located in the United States:

	Operated Wells		Nonoperated Wells		Total (a)	
	Gross	Net	Gross	Net	Gross	Net
Gas	10,524.3	9,148.3	7,504.8	1,399.6	18,029.1	10,547.9
Oil	2,611.7	2,280.8	4,522.2	575.1	7,133.9	2,855.9
Total	13,136.0	11,429.1	12,027.0	1,974.7	25,163.0	13,403.8

(a) 930.1 gross (681.8 net) gas wells and 19.9 gross (18.0 net) oil wells are dual completions.

Drilling Activity

The following table summarizes the number of wells drilled during the years indicated. As of December 31, 2007, we were in the process of drilling 595 gross (422.4 net) wells.

	Year Ended December 31					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Completed as —						
Gas wells	1,275	901.2	1,148	725.1	791	499.8
Oil wells	269	139.3	316	169.1	255	121.4
Non-productive	12	7.6	11	3.3	19	9.6
Total	1,556	1,048.1	1,475	897.5	1,065	630.8
Exploratory wells:						
Completed as —						
Gas wells	51	17.4	22	8.1	7	4.7
Oil wells	1	1.0	–	–	–	–
Non-productive	9	6.8	10	7.2	2	2.0
Total	61	25.2	32	15.3	9	6.7
Total (a)	1,617	1,073.3	1,507	912.8	1,074	637.5

(a) Included in totals are 535 gross (106.0 net) wells in 2007, 581 gross (119.5 net) wells in 2006 and 472 gross (96.7 net) wells in 2005, 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, 2007. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed Acres (a)(b)		Undeveloped Acres	
(in thousands)	Gross	Net	Gross	Net
Texas	1,191	831	663	544
Arkansas	610	333	135	121
Oklahoma	580	407	254	129
New Mexico	562	350	19	17
Utah	289	168	154	99
Montana	272	44	85	36
Kansas	211	167	–	–
Louisiana	139	73	86	28
Colorado	112	87	5	5
Wyoming	99	67	67	60
Other	34	15	33	13
Total	4,099	2,542	1,501	1,052

(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.

capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

Oil and Gas Production, Sales Prices and Production Costs

The following table shows the total and average daily production, the average sales prices per unit of production and the production expense and taxes, transportation and other expense per Mcfe for the indicated periods:

	Year Ended December 31		
	2007	2006	2005
Total production:			
Gas (Mcf)	532,097,846	433,010,577	377,097,181
Natural gas liquids (Bbls)	4,943,781	4,326,853	3,812,420
Oil (Bbls)	17,172,191	16,440,079	14,253,718
Mcfe	664,793,678	557,612,169	485,494,009
Average daily production:			
Gas (Mcf)	1,457,802	1,186,330	1,033,143
Natural gas liquids (Bbls)	13,545	11,854	10,445
Oil (Bbls)	47,047	45,041	39,051
Mcfe	1,821,353	1,527,705	1,330,121
Average sales prices (a):			
Gas (per Mcf)	$ 7.50	$ 7.69	$ 7.04
Natural gas liquids (per Bbl)	$ 45.37	$ 37.03	$ 34.10
Oil (per Bbl)	$ 70.08	$ 60.96	$ 47.03
Production expense per Mcfe	$ 0.93	$ 0.88	$ 0.84
Production and property taxes per Mcfe	$ 0.38	$ 0.41	$ 0.42
Transportation and other expense per Mcfe	$ 0.29	$ 0.26	$ 0.21

(a) The sales prices shown include the effects of hedging. The effect of hedging on gas prices was to increase realized prices by $1.24 in 2007 and $1.43 in 2006 and to decrease realized prices by $0.34 in 2005. The effect of hedging on oil prices was to increase realized prices by $1.40 in 2007 and $0.17 in 2006 and to decrease realized prices by $5.25 in 2005.

DELIVERY COMMITMENTS

Under a production payment sold in 1998, we committed to deliver 16 Bcf beginning September 2006. The committed volumes are in East Texas. As of December 31, 2007, remaining volumes to be delivered under this commitment are 12 Bcf.

As part of the July 2007 Dominion acquisition, Dominion retained interests in certain of the acquired properties. Under the terms of the acquisition and the retained interest agreements, Dominion retained the rights to approximately 13 Bcf of gas beginning from the date of acquisition through February 2009. As of December 31, 2007, remaining volumes to be delivered to Dominion are 7 Bcf.

The Company's production and reserves are adequate to meet these delivery commitments. See Note 8 to Consolidated Financial Statements.

COMPETITION AND MARKETS

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

FEDERAL AND STATE LAWS AND REGULATIONS

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

are subject to federal regulation by the Federal Energy Regulatory Commission. Federal wellhead price controls on all domestic gas were terminated on January 1, 1993, and none of our gathering systems are currently subject to FERC regulation. On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder. FERC has promulgated new regulations to implement the Energy Policy Act. 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 our production or on our gas transportation business cannot be predicted. We, however, do not believe that we 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.

On December 19, 2007, the President signed into law the Energy Independence & Security Act of 2007 (PL 110-140). The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline, or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations, and establishes penalties for violations thereunder. We cannot predict the impact of future government regulation on any natural gas facilities.

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 operation 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. Two of our gathering subsidiaries are designated gas utilities and are subject to such state regulations. 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 we cannot predict whether any further rules will be adopted or, if adopted, the effect these rules may have on our 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 relating to protection of the environment directly impact oil and gas exploration, development and production operations, and consequently may impact our operations and costs. These laws and regulations govern, among other things, emissions to the atmosphere, discharges of pollutants into waters of the United States, underground injection of waste water, the generation, storage, transportation and disposal of waste materials, and protection of public health, natural resources and wildlife. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas. In some jurisdictions, the laws and regulations are constantly being revised, creating the potential for delays in development plans.

where such wastes have been taken for disposal. In addition, petroleum hydrocarbons or wastes may have been disposed of or released by prior operators of properties we are acquiring as well as by current third party operators of properties in which we have an ownership interest. Properties impacted by any such disposal or releases could be subject to costly and stringent investigatory or remedial requirements under environmental laws, some of which impose strict, joint and several liability without regard to fault or the legality of the original conduct, including the Comprehensive Environmental Response, Compensation, and Liability Act, also known as "CERCLA" or the "Superfund" law and analogous state laws.

We are committed to environmental protection and believe we are in substantial compliance with applicable environmental laws and regulations. We routinely obtain permits for our facilities and operations in accordance with the applicable laws and regulations. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations. We have made and will continue to make expenditures in our efforts to comply with environmental regulations and requirements. These costs are considered a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with government regulations.

We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our financial position or operations. However, due to continuing changes in these laws and regulations and judicial construction of same, we are unable to predict with any reasonable degree of certainty our future costs of complying with these governmental requirements. We have been able to plan for and comply with new initiatives without materially changing our operating strategies.

We maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, produced water or other substances. We are not fully insured against all environmental risks, and no coverage is maintained with respect to any penalty or fine required to be paid by us.

Future Laws and Regulations

The oil and gas industry is highly regulated and, from time to time, Congress and state legislatures consider broad and sweeping policy changes that may affect the industry. We cannot predict the impact of such future legislative or regulatory initiatives.

EMPLOYEES

We had 2,361 employees as of December 31, 2007. 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, 59, was a founder of the Company and has been Chairman and Chief Executive Officer 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.

Keith A. Hutton, 49, has been President since May 1, 2005. Prior thereto, Mr. Hutton served as 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, 53, has been Senior Executive Vice President and Chief of Staff since May 1, 2005. Prior thereto, Mr. Vennerberg served as 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).

Louis G. Baldwin, 58, 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.

Timothy L. Petrus, 53, has been Executive Vice President — Acquisitions since May 1, 2005. Prior thereto, Mr. Petrus served as Senior Vice President — Acquisitions or held similar positions with the Company since 1988. Prior to that time, Mr. Petrus was employed by Texas American Bank and Exxon Corporation.

Bennie G. Kniffen, 57, 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.

Risk Factors

The following factors, among others, could cause actual results to differ materially from those contained in forward-looking statements made in this report and presented elsewhere by management from time to time. Such factors, among others, may have a material adverse effect upon our business, financial condition, and results of operations.

The following discussion of our risk factors should be read in conjunction with the consolidated financial statements and related notes included herein. Because of these and other factors, past financial performance should not be considered an indication of future performance.

Oil, natural gas and natural gas liquids prices fluctuate due to a number of uncontrollable factors, and any decline will adversely affect our financial condition.

Our results of operations depend upon the prices we receive for our natural gas, oil and natural gas liquids. We sell most of our natural gas, oil and natural gas liquids at current market prices rather than through fixed-price contracts. Historically, the markets for natural gas, oil and natural gas liquids have been volatile and are likely to remain volatile in the future. The prices we receive depend upon factors beyond our control, which include:

- weather conditions;
- political instability or armed conflict in oil-producing regions, such as current conditions in the Middle East, Nigeria and Venezuela;
- the supply of domestic and foreign oil, natural gas and natural gas liquids;
- the ability of members of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production levels;
- the level of consumer demand;
- worldwide economic conditions;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes;
- the proximity to and capacity of transportation facilities; and
- the effect of worldwide energy conservation measures.

Government regulations, such as regulations of natural 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 natural gas.

To the extent we have not hedged our production, any decline in natural gas and oil 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.

Our use of hedging arrangements could result in financial losses or reduce our income.

To reduce our exposure to fluctuations in natural gas, oil and natural gas liquids prices, we have entered into and expect in the future to enter into hedging arrangements for a portion of our natural gas, oil and natural gas liquids production. However, we may not be able to hedge our future production at prices we deem attractive. 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 contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in natural gas, oil and natural gas liquids prices.

We make, and will continue to make, substantial capital expenditures for the acquisition, development, exploration and abandonment of our oil and natural gas reserves. We intend to finance our capital expenditures primarily through cash flow from operations, bank and commercial paper borrowings and public and private equity and debt offerings. Lower oil and natural gas prices, however, would reduce our cash flow and could affect our access to the capital markets. Costs of exploration and development were $2.8 billion in 2007, $2.1 billion in 2006 and $1.4 billion in 2005. During 2007, we spent $3.2 billion on proved property acquisitions and $831 million on unproved property acquisitions. Our exploration and development budget for 2008 is $2.6 billion. An additional $400 million has been budgeted for the construction of pipeline infrastructure and compression and processing facilities in 2008.

We believe that, after debt service, we will have sufficient cash from operating activities to finance our exploration and development expenses through 2008. If revenues decrease, however, and we are unable to obtain additional debt or equity financing, we may lack the capital necessary to replace our reserves or to maintain production at current levels.

We have substantial indebtedness and may incur substantially more debt. Any failure to meet our debt obligations would adversely affect our business and financial condition.

We have incurred substantial debt. As a result of our indebtedness, we will need to use a portion of our cash flow to pay principal and interest, which will reduce the amount available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our bank revolving credit, term loans and commercial paper indebtedness is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate protection hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

Together with our subsidiaries, we may incur substantially more debt in the future. The indentures governing our outstanding public debt do not contain restrictions on our incurrence of additional indebtedness. To the extent new debt is added to our current debt levels, the risks resulting from indebtedness could substantially increase.

Our access to the commercial paper market is predicated on continued acceptable short-term ratings by Standard & Poors and Moody's. Any downgrade in those ratings may impact our borrowing costs as well as our access to the commercial paper market. Additionally, any downgrade to our long-term ratings could increase our borrowings costs and limit our access to capital markets.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance the debt, sell assets or sell shares of common stock on terms that we do not find attractive if it can be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under the indebtedness, which could adversely affect our business, financial condition and results of operations.

Competition in the oil and natural gas industry is intense, and some of our competitors have greater financial, technological and other resources than we have.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, exploration and production. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies in each of the following areas:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our oil and natural gas production;
- integrating new technologies;
- seeking to acquire the equipment and expertise necessary to develop and operate our properties; and
- hiring qualified people.

Some of our competitors have financial, technological and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies may be able to pay more for development prospects and productive oil and natural 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. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to develop and exploit our oil and natural 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.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when oil and natural gas are produced unless we continue to conduct successful exploitation, development or exploration activities or acquire properties containing proved reserves, or both. We may not be able to economically find, develop or acquire additional reserves. Furthermore, while our revenues may increase if oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

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

Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions or changes in conditions could cause the quantities and net present value of our reserves to be overstated.

To prepare estimates of economically recoverable oil and natural gas reserves and future net cash flows, we analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We also analyze available geologic, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs. Actual results most likely will vary from our estimates. Any significant variance could reduce the estimated quantities and present value of reserves shown in this annual report.

You should not assume that the present value of future net cash flows from our proved reserves shown in this annual report is the current market value of our estimated oil and natural gas reserves. In accordance with Securities and Exchange Commission requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may differ materially from those used in the net present value estimate, and as a result, net present value estimates using current prices and costs may be significantly less than the estimate which is provided in this annual report.

Producing and unproved property acquisitions are a component of our growth strategy, and our failure to complete future acquisitions successfully could reduce our earnings and slow our growth.

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

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities.

Our recent growth is due in part to acquisitions of both producing and unproved properties, and we expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, exploration and development potential, lease terms, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not allow us to become sufficiently familiar with the properties, and we do not always discover structural, subsurface and environmental problems that may exist or arise. Our review prior to signing a definitive purchase agreement may be even more limited.

We generally are not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities, on acquisitions. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. If material breaches are discovered by us prior to closing, we could require adjustments to the purchase price, or, if the claims are significant, we or the seller may have a right to terminate the agreement. We could also fail to discover breaches or defects prior to closing and incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, for which we would have limited or no contractual remedies or insurance coverage.

increased scope, geographic diversity and complexity of our operations.

Increasing our reserve base through acquisitions is an important part of our business strategy. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in our incurring unanticipated expenses and losses. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations.

Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results.

Our development and exploratory drilling efforts and our operations of our wells may not be profitable or achieve our targeted returns.

We acquire significant amounts of unproved property in order to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire both producing and unproved properties as well as lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells. Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and oil and our ability to add reserves at an acceptable cost. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of unproved property or drilling a well, whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

Drilling oil and natural gas wells is a high-risk activity and subjects us to a variety of factors that we cannot control.

Drilling oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive oil and natural gas reservoirs. We may not recover all or any portion of our investment in new wells. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling activities to be unsuccessful and result in a total loss of our investment. In addition, we often are uncertain as to the future cost or timing of drilling, completing and operating wells. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions, including urban drilling;
- title problems;
- restricted access to land for drilling or laying pipeline;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions; and
- costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and equipment.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control.

The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities, as well as any delays in constructing new infrastructure facilities, could harm our business. We deliver oil and natural gas through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to market conditions or mechanical reasons, or may not be available to us in the future.

We are subject to complex federal, state and local laws and regulations that could adversely affect our business.

Extensive federal, state and local regulation of the oil and gas industry significantly affects our operations. In particular, our oil and natural 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

- discharge permits for drilling operations;
- drilling bonds;
- spacing of wells;
- unitization and pooling of properties;
- environmental protection;
- reports concerning operations; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property damage;
- oil spills;
- discharge of hazardous materials;
- reclamation costs;
- remediation and clean-up costs; and
- other environmental damages.

Although we believe that our operations generally comply with applicable laws and regulations, failure to comply could result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Further, these laws and regulations could change in ways that substantially increase our costs. Any of these liabilities, penalties, suspensions, terminations or regulatory changes could make it more expensive for us to conduct our business or cause us to limit or curtail some of our operations.

We currently own, lease or expect to acquire, and have in the past owned or leased, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although we have used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed or released on or under the properties owned or leased by us or on or under other locations where such wastes were taken for disposal. In addition, petroleum hydrocarbons or wastes may have been disposed or released by prior operators of properties that we are acquiring as well as by current third party operators of properties in which we have an ownership interest. Properties impacted by any such disposal or release could be subject to costly and stringent investigatory or remedial requirements under environmental laws, some of which impose strict joint and several liability without regard to fault or the legality of the original conduct. These laws include the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as "CERCLA" or the "Superfund" law, the federal Resource Conservation and Recovery Act and analogous state laws. Under these laws and any implementing regulations, we could be required to remediate contaminated properties and take actions to compensate for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or wastes into the environment. We currently do not expect any remedial obligations imposed under environmental laws to have a significant effect on our operations.

Our operations in the coastal waters of Cook Inlet of Alaska are subject to the federal Oil Pollution Act, which imposes a variety of requirements related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. The Oil Pollution Act imposes strict joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. Liability limits for offshore facilities require a responsible party to pay all removal costs, plus up to $75 million in other damages. These liability limits do not apply, however, if the spill was caused by gross negligence or willful misconduct of the party, if the spill resulted from violation of a federal safety, construction or operation regulation, or if the party failed to report the spill or cooperate fully in any resulting cleanup. The Oil Pollution Act also requires a responsible party at an offshore facility to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe that our operations are in substantial compliance with Oil Pollution Act requirements.

The Department of Transportation, through the Office of Pipeline Safety and Research and Special Programs Administration, has implemented a series of rules requiring operators of natural gas and hazardous liquid pipelines to develop integrity management plans for pipelines that, in the event of a failure, could impact certain high consequence areas. These rules also require operators to conduct baseline integrity assessments of all applicable pipeline segments located in the high consequence areas. We are currently

Our business involves many operating risks that may result in substantial losses, and insurance may be unavailable or inadequate to protect us against these risks.

Our operations are subject to hazards and risks inherent in drilling for, producing and transporting oil and natural gas, such as:

- fires;
- natural disasters;
- explosions;
- pressure forcing oil or natural gas out of the wellbore at a dangerous velocity coupled with the potential for fire or explosion;
- weather;
- failure of oilfield drilling and service tools;
- changes in underground pressure in a formation that causes the surface to collapse or crater;
- pipeline ruptures or cement failures; and
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases.

Any of these risks can cause substantial losses resulting from:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We do not insure against the loss of oil or natural gas reserves as a result of operating hazards or insure against business interruption. Losses could occur from uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operations.

Terrorist activities and military and other actions could adversely affect our business.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scope, and the United States and others instituted military action in response. These conditions caused instability in world financial markets and generated global economic instability. The continued threat of terrorism and the impact of military and other action, including U.S. military operations in Afghanistan and Iraq, will likely lead to continued volatility in crude oil and natural gas prices and could affect the markets for our operations. In addition, future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risks and, depending on their ultimate magnitude, could have a material adverse effect on our business.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns or lead to unexpected future costs.

Item 1B.
Unresolved Staff Comments

As of December 31, 2007, we do not have any Securities and Exchange Commission staff comments that have been unresolved for more than 180 days.

Item 3.
Legal Proceedings

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the U.S. District Court for the Western District of Oklahoma by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the U.S. False Claims Act against the Company and certain of our subsidiaries. The plaintiff alleges that we underpaid royalties on natural gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% as a result of mismeasuring the volume of natural gas, incorrectly analyzing its heating content and improperly valuing the natural gas during at least the past ten years. The plaintiff seeks treble damages for the unpaid royalties (with interest, attorney fees and expenses), civil penalties between $5,000 and $10,000 for each violation of the U.S. False Claims Act, and an order for us to cease the allegedly improper measuring practices. This lawsuit against us and similar lawsuits filed by Grynberg against more than 300 other companies were consolidated in the United States District Court for Wyoming. In October 2002, the court granted a motion to dismiss Grynberg's royalty valuation claims, and Grynberg's appeal of this decision was dismissed for lack of appellate jurisdiction in May 2003. In response to a motion to dismiss filed by us and other defendants, in October 2006 the district judge held that Grynberg failed to establish jurisdictional requirements to maintain the action against us and other defendants and dismissed the action for lack of subject matter jurisdiction. In September 2007, the district judge dismissed those claims against us pertaining to the royalty value of carbon dioxide. Grynberg has filed appeals of these decisions. While we are unable to predict the final outcome of this case, 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 July 2005 a predecessor company, Antero Resources Corporation, was served with a lawsuit styled *Threshold Development Company, et al. v. Antero Resources Corp.*, which lawsuit was filed in the District Court of Wise County, Texas. The plaintiffs are surface owners, royalty owners and prior working interest owners in several oil and gas leases as well as other contractual agreements under which Antero Resources Corporation owned an interest. Antero Resources Corporation, the defendant, was acquired by us on April 1, 2005. The claims relate to alleged events pre-dating the acquisition and concern non-payment of royalties, improper calculation of royalties, improper pricing related to royalties, trespass, failure to develop and breach of contract. We have settled all claims related to the payment of royalties and trespass. Under the remaining claims, the plaintiffs are seeking both damages and termination of the existing oil and gas leases covering their interests. The court has ordered the parties to mediation, which has not been scheduled. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Based on a review of the current facts and circumstances with counsel, management has provided for what is believed to be a reasonable estimate of the loss exposure for this matter. While acknowledging the uncertainties of litigation, management believes that the ultimate outcome of this matter will not have a material effect on its earnings, cash flows or financial position.

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

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2007.

Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

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 closing prices and cash dividends declared for each quarter of 2007 and 2006 (as adjusted for the five-for-four stock split effected in December 2007 and the May 2006 distribution of the Hugoton Royalty Trust units):

	High	Low	Cash Dividend
2007			
First Quarter	$ 44.46	$ 35.48	$ 0.096
Second Quarter	50.82	43.42	0.096
Third Quarter	50.37	41.98	0.096
Fourth Quarter	53.66	48.50	0.120
2006			
First Quarter	$ 38.04	$ 30.80	$ 0.060
Second Quarter	36.91	29.58	0.060
Third Quarter	38.68	31.52	0.060
Fourth Quarter	40.48	32.00	0.072

The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Board of Directors and will depend on our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters the Board of Directors deems relevant.

In November 2007, the Board of Directors declared a five-for-four stock split of its common stock and declared a quarterly dividend of $0.12, effecting a 25% dividend increase. On February 19, 2008, the Board of Directors declared a quarterly dividend of $0.12 per common share, payable on April 15, 2008 to stockholders of record on March 31, 2008. On February 21, 2008, we had 2,074 stockholders of record.

In January 2006, the Board of Directors declared a dividend to common stockholders, consisting of all 21.7 million Hugoton Royalty Trust units owned by us. The dividend ratio of 0.047688 trust units for each common share outstanding was set on the record date of April 26, 2006. The units were distributed on May 12, 2006, when this dividend was recorded at approximately $1.35 per common share, based on the fair market value of the units on that date.

The following summarizes purchases of our common stock during fourth quarter 2007:

Month	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October	215,711	$ 50.78	–	
November	212,065	$ 51.52	–	
December	1,326	$ 51.82	–	
Total	429,102 (2)	$ 51.15	–	22,208,000

(1) The Company has a repurchase program approved by the Board of Directors in August 2004 for the repurchase of up to 25 million shares of the Company's common stock.

(2) Does not include performance or restricted share forfeitures. Includes 124,769 shares and 25,938 shares of common stock purchased during the quarter from employees in connection with the settlement of income tax withholding obligations upon vesting of restricted shares and performance shares, respectively, under the 2004 Stock Incentive Plan. Also includes 278,395 shares of common stock delivered or attested to in satisfaction of the exercise price upon the exercise of employee stock options under both the 1998 and 2004 Stock Incentive plans. These share purchases were not part of a publicly announced program to purchase common shares.

Selected Financial Data

The following table shows selected financial information for each of the years in the five-year period ended December 31, 2007. Significant producing property acquisitions in each of the years presented affect the comparability of year-to-year financial and operating data. See Items 1 and 2, Business and Properties, "Acquisitions." All weighted average shares and per share data have been adjusted for the five-for-four stock split effected in December 2007, the four-for-three stock split effected in March 2005, the five-for-four stock split effected in March 2004 and the four-for-three stock split effected in March 2003. 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 millions except production, per share and per unit data)	2007	2006	2005	2004	2003
Consolidated Income Statement Data					
Revenues:					
Gas and natural gas liquids	$ 4,214	$ 3,490	$ 2,787	$ 1,613	$ 1,040
Oil and condensate	1,204	1,002	670	319	135
Gas gathering, processing and marketing	100	86	56	18	13
Other	(5)	(2)	6	(2)	1
Total Revenues	$ 5,513	$ 4,576	$ 3,519	$ 1,948	$ 1,189
Net Income	$ 1,691 (a)	$ 1,860 (b)	$ 1,152 (c)	$ 508 (d)	$ 288 (e)
Earnings per common share:					
Basic	$ 3.58	$ 4.08	$ 2.57	$ 1.22	$ 0.77 (f)
Diluted	$ 3.53	$ 4.02	$ 2.52	$ 1.21	$ 0.76 (f)
Weighted average common shares outstanding	471.9	456.1	448.1	416.1	374.6
Cash dividends declared per common share	$ 0.408	$ 0.252 (g)	$ 0.180	$ 0.072	$ 0.019 (h)
Consolidated Statement of Cash Flows Data					
Cash provided (used) by:					
Operating activities	$ 3,639	$ 2,859	$ 2,094	$ 1,217	$ 794
Investing activities	$ (7,345)	$ (3,036)	$ (2,908)	$ (2,518)	$ (1,135)
Financing activities	$ 3,701	$ 180	$ 806	$ 1,304	$ 333
Consolidated Balance Sheet Data					
Property and equipment, net	$ 17,200	$ 10,824	$ 8,508	$ 5,624	$ 3,312
Total assets	$ 18,922	$ 12,885	$ 9,857	$ 6,110	$ 3,611
Long-term debt	$ 6,320	$ 3,451	$ 3,109	$ 2,043	$ 1,252
Stockholders' equity	$ 7,941	$ 5,865	$ 4,209	$ 2,599	$ 1,466
Operating Data					
Average daily production:					
Gas (Mcf)	1,457,802	1,186,330	1,033,143	834,572	668,436
Natural gas liquids (Bbls)	13,545	11,854	10,445	7,484	6,463
Oil (Bbls)	47,047	45,041	39,051	22,696	12,943
Mcfe	1,821,353	1,527,705	1,330,121	1,015,654	784,877
Average sales price:					
Gas (per Mcf)	$ 7.50	$ 7.69	$ 7.04	$ 5.04	$ 4.07
Natural gas liquids (per Bbl)	$ 45.37	$ 37.03	$ 34.10	$ 26.44	$ 19.99
Oil (per Bbl)	$ 70.08	$ 60.96	$ 47.03	$ 38.38	$ 28.59
Production expense (per Mcfe)	$ 0.93	$ 0.88	$ 0.84	$ 0.66	$ 0.58
Taxes, transportation and other expense (per Mcfe)	$ 0.67	$ 0.67	$ 0.63	$ 0.47	$ 0.37
Proved reserves:					
Gas (Mcf)	9,441.1	6,944.2	6,085.6	4,714.5	3,644.2
Natural gas liquids (Bbls)	66.8	53.0	47.4	38.5	34.7
Oil (Bbls)	241.2	214.4	208.7	152.5	55.4
Mcfe	11,289.0	8,548.6	7,622.2	5,860.3	4,184.9
Other Data					
Ratio of earnings to fixed charges (i)	9.6	15.2	11.7	8.9	6.9

Texas margin tax of $34 million and a $39 million non-cash derivative fair value gain.

(c) Includes pre-tax effects of a $39 million non-cash derivative fair value gain, non-cash performance award compensation of $34 million, and a gain of $10 million on the exchange of producing properties.

(d) Includes pre-tax effects of a $6 million non-cash derivative fair value loss, stock-based incentive compensation of $89 million and special bonuses totaling $12 million related to the ChevronTexaco and ExxonMobil acquisitions. Stock-based incentive compensation includes cash compensation of $22 million related to cash-equivalent performance shares.

(e) Includes pre-tax effects of a $10 million non-cash derivative fair value loss, a non-cash contingency gain of $2 million, non-cash performance award compensation of $53 million, a $10 million loss on extinguishment of debt, a $16 million non-cash gain on the distribution of Cross Timbers Royalty Trust units, and a $2 million after-tax gain on adoption of the new accounting standard for asset retirement obligation.

(f) Before cumulative effect of accounting change, earnings per share were $0.76 basic and $0.75 diluted.

(g) Excludes the May 2006 distribution of all of the Hugoton Royalty Trust units owned by the Company to its stockholders as a dividend with a market value of approximately $1.35 per common share.

(h) Excludes the September 2003 distribution of all of the Cross Timbers Royalty Trust units owned by the Company to its stockholders as a dividend with a market value of approximately $0.07 per common share.

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

PART II

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 the Consolidated Financial Statements at Item 15(a). Unless otherwise indicated, throughout this discussion the term "Mcfe" refers to thousands of cubic feet of gas equivalent quantities produced for the indicated period, with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

OVERVIEW

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

In 2007, we achieved the following record financial and operating results:

- Average daily gas production was 1.46 Bcf, a 23% increase from 2006, average daily oil production was 47,047 Bbls, a 4% increase from 2006, and average daily natural gas liquids production was 13,545 Bbls, a 14% increase from 2006.
- Year-end proved reserves were 11.29 Tcfe, a 32% increase from year-end 2006.
- Cash flow from operating activities was $3.6 billion, a 27% increase from 2006.
- Year-end stockholders' equity was $7.9 billion, a 35% increase from year-end 2006.

We achieve production and proved reserve growth primarily through acquisitions of both producing and unproved properties, followed by low-risk development generally funded by cash flow from operating activities. Funding sources for our acquisitions include proceeds from sales of public and private equity and debt, bank or commercial paper borrowings and cash flow from operating activities. During 2007, we acquired $3.2 billion of proved properties with proved reserves of 1.3 Tcf of natural gas, 2.7 million Bbls of natural gas liquids and 11.3 million Bbls of oil, as well as $831 million of unproved properties.

In a trend that began in 2004 and accelerated during 2005 and the first half of 2006, commodity prices for natural gas, natural gas liquids and oil increased significantly (see "Significant Events, Transactions and Conditions — Product Prices"). The higher prices have led to increased activity in the industry and, consequently, rising costs. Drilling rig counts are at levels not seen since the last boom in the early 1980s and labor to run the rigs is in short supply. This was further aggravated by the damage in the Gulf of Mexico as a result of the August and September 2005 hurricanes. These cost trends have put pressure not only on our operating costs but also our capital costs. With the increased activity, there is also increased demand for oil and gas properties which has resulted in higher acquisition prices. While prices for natural gas have been relatively flat since the second half of 2006, oil prices in the second half of 2007 began to increase significantly. The leveling off of natural gas prices has resulted in slowing cost inflation.

have been able to grow our production through acquisitions and drilling, adding more reserves than we produce. We also attempt to manage our natural decline by combining the acquisition of mature properties with shallower decline rates with the drilling of new wells that have higher decline rates. This has allowed us to keep our natural decline rate lower than the industry average. Future growth will depend on our ability to continue to add reserves in excess of production.

Our goal for 2008 is to increase production by 20%. To achieve future production and reserve growth, we will continue to pursue acquisitions that meet our criteria and to complete development projects included in our inventory of between 9,500 and 10,300 identified potential drilling locations. Our 2008 development budget is $2.6 billion. While an acquisition budget has not been formalized, we expect to complete acquisitions of both producing and unproved properties for approximately $1.0 billion, during the first quarter of 2008. These acquisitions will be funded both by commercial paper borrowings and by proceeds from the February 2008 common stock offering and are subject to typical post-closing adjustments. We plan to actively review additional acquisition opportunities during 2008. We cannot ensure that we will be able to find properties that meet our acquisition criteria and that we can purchase such properties on acceptable terms (see "Liquidity and Capital Resources — Capital Expenditures").

Increased activity in the oil and gas producing industry has also had an effect on our ability to hire qualified people including not only operational employees, but also all classifications of industry-specific professionals. We continue to find the employees we need to adequately staff our operations; however, the cost of hiring and the time to fill positions has increased. Our employee turnover continues to remain low with total turnover of 9.6% in 2007 and 8.4% in 2006.

In the event that our operating cash flow exceeds our development, exploration and acquisition capital needs, we will consider other alternative uses for this cash including, but not limited to, debt repayment or stock repurchases. In August 2004, the Board of Directors authorized the repurchase of up to 25 million shares of our common stock from time to time in the open market or negotiated transactions. As of December 31, 2007, 2.8 million shares have been repurchased under this authorization.

Sales prices for our natural gas, oil and natural gas liquids production are influenced by supply and demand conditions over which we have little or no control, including weather and regional and global economic conditions. To provide predictable production growth, we may hedge a portion of our production at commodity prices management deems attractive to ensure stable cash flow margins to fund our operating commitments and development program. As of February 2008, we have hedged approximately 65% of our 2008 projected gas production at an average NYMEX price of $8.32 per Mcf, about 60% of our 2008 crude oil production at an average NYMEX price of $74.20 per Bbl and about 30% of our 2008 natural gas liquids production at an average price of $44.22 per Bbl. Our average realized price on hedged production will be lower than these average NYMEX prices because of location, quality and other adjustments.

The combined effect of higher product prices, a 23% increase in gas production, a 4% increase in oil production and a 14% increase in natural gas liquids production resulted in a 20% increase in total revenues to $5.5 billion in 2007 from $4.6 billion in 2006. On an Mcfe produced basis, total revenues were $8.29 in 2007, a 1% increase from $8.21 in 2006.

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

	2007	2006	Increase (Decrease)
Production	$ 0.93	$ 0.88	6%
Taxes, transportation and other	0.67	0.67	–
Depreciation, depletion and amortization	1.78	1.57	13%
Accretion of discount in asset retirement obligation	0.03	0.03	–
General and administrative, excluding stock compensation	0.25	0.22	14%
Interest	0.38	0.32	19%
	$ 4.04	$ 3.69	9%

Production expense per Mcfe rose 6% primarily because of increased maintenance costs. Taxes, transportation and other expense generally is based on product revenues. An increase in transportation and other expense as a result of higher product prices was offset by lower production taxes and lower property taxes. The lower production taxes were primarily due to the benefit of increased gas volumes from new drill wells which were subject to reduced production tax rates. The 13% increase in depreciation, depletion and amortization per Mcfe resulted from higher acquisition, development and facility costs. The 14% increase in all other general and administrative expense per Mcfe is because of increased personnel and other costs related to Company growth. The 19% increase in interest expense is primarily because of an increase in weighted average borrowings to fund recent acquisitions.

Significant expenses that generally do not trend with production include:

Stock compensation. Stock compensation expense was $65 million in 2007 compared to $63 million in 2006.

The net derivative fair value gain was $11 million in 2007 compared to $102 million in 2006.

Our primary sources of liquidity are cash flow from operating activities, borrowings under either our revolving credit agreement, our commercial paper program, or our other unsecured and uncommitted lines of credit and public and private offerings of equity and debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk (See "Liquidity and Capital Resources — Financing").

SIGNIFICANT EVENTS, TRANSACTIONS AND CONDITIONS

The following events, transactions and conditions affect the comparability of results of operations and financial condition for each of the years ended December 31, 2007, 2006 and 2005 and may impact future operations and financial condition.

Acquisitions. We acquired proved and unproved properties at a total cost of $4.0 billion in 2007, $786 million in 2006 and $2.0 billion in 2005, which were funded by a combination of proceeds from sales of common stock and senior notes, bank borrowings and cash flow from operating activities. The following are significant acquisitions in each of these years:

Closing Date		Seller	Amount (in millions)	Acquisition Area
2007	July	Dominion Resources, Inc.	$2,576 (a)	Rocky Mountain Region, San Juan Basin and South Texas
	October	Various	550	Barnett Shale of North Texas
2006	February	Total E&P USA, Inc.	300	East Texas and Mississippi
	June	Peak Energy Resources Inc.	150 (b)	Barnett Shale of North Texas
2005	April	Antero Resources Corporation	814 (c)	Barnett Shale of North Texas
	May	Plains Exploration & Production Company	336	East Texas and northwestern Louisiana
	July	ExxonMobil Corporation	200	Permian Basin of West Texas and New Mexico

(a) Represents a portion of the allocated purchase price of Dominion Resources, Inc. and includes an allocation of $2.5 billion to proved properties and $73 million to unproved properties. See Note 13 to the Consolidated Financial Statements.

(b) Represents a portion of the allocated purchase price of Peak Energy Resources, Inc. and includes an allocation of $97 million to proved properties and $53 million to unproved properties. See Note 13 to the Consolidated Financial Statements.

(c) Represents a portion of the allocated purchase price of Antero Resources Corporation and includes an allocation of $634 million to proved properties and $180 million to unproved properties. See Note 13 to the Consolidated Financial Statements.

2007, 2006 and 2005 Development and Exploration Programs. Gas development focused on the Eastern and North Texas Regions during 2007, 2006 and 2005. Oil development was concentrated primarily in the Permian Region during all three years. Development costs totaled $2.5 billion in 2007, $2.0 billion in 2006 and $1.3 billion in 2005. Exploration activity in 2007 and 2006 was primarily drilling and geological and geophysical analysis, including seismic studies of underdeveloped properties in South Texas. Exploratory costs were $257 million in 2007, $123 million in 2006 and $52 million in 2005. Our development and exploration activities are generally funded by cash flow from operations.

2008 Acquisition, Development and Exploration Program. We have budgeted $2.6 billion for our 2008 development and exploration program, which we expect to fund using cash flow from operations. While an acquisition budget has not been formalized, we expect to complete acquisitions of both producing and unproved properties for approximately $1.0 billion during the first quarter of 2008. These acquisitions will be funded both by commercial paper borrowings and by proceeds from the February 2008 common stock offering and are subject to typical post-closing adjustments. We plan to continue to actively review additional acquisition opportunities during 2008. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, our commercial paper program, public or private issuance of debt or equity, or asset sales. The cost of 2008 property acquisitions may alter the amount currently budgeted for development and exploration. Our total budget for acquisitions, development and exploration will be adjusted throughout 2008 to focus on opportunities offering the highest rates of return. Additionally, $400 million has been budgeted for the construction of pipeline infrastructure and compression and processing facilities.

As of December 31, 2007, we have an inventory of between 9,500 and 10,300 identified potential drilling locations. We plan to drill about 1,160 (980 net) development wells and perform approximately 750 (600 net) workovers and recompletions in 2007. Drilling plans are dependent upon product prices.

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

Gas. Natural gas prices are affected by weather, the U.S. economy, the level of North American production, crude oil prices and import levels of liquefied natural gas. Natural gas competes with alternative energy sources as fuel for heating and the generation of electricity. Natural gas prices rose sharply in the second half of 2005 due to the effects of hurricanes on Gulf of Mexico of hurricane activity in the Gulf of Mexico. Much colder temperatures in early 2007 caused prices to partially rebound, however, the absence of hurricane activity in the Gulf of Mexico in 2007 has kept prices relatively flat. We expect prices to remain volatile. As described under "Hedging Activities" below, we use commodity price hedging instruments to reduce our exposure to gas price fluctuations. The following are comparative average gas prices for the last three years:

	Year Ended December 31		
(per Mcf)	2007	2006	2005
Average NYMEX price	$ 6.86	$ 7.23	$ 8.62
Average realized sales price	$ 7.50	$ 7.69	$ 7.04
Average realized sales price excluding hedging	$ 6.26	$ 6.26	$ 7.38

At February 12, 2008, the average NYMEX gas price for the following 12 months was $8.91 per MMBtu. As computed on an energy equivalent basis, our proved reserves were 84% natural gas at December 31, 2007. After considering hedges in place as of February 15, 2008, we estimate that a $0.10 per Mcf change in the average gas sales price would result in approximately a $20 million change in 2008 annual operating cash flow before income taxes.

Oil. Crude oil prices are generally determined by global supply and demand. Oil prices have risen primarily because of increasing global demand and supply shortage concerns, inadequate sour crude refining capacity, reduced production as a result of tropical storms and hurricanes in the Gulf of Mexico in 2005 and political instability in some oil producing countries. In the last few months of 2007 and early 2008, rising tensions in the Middle East, weakness in the dollar and strong demand caused prices to reach record levels of $100 per Bbl. We expect oil prices to remain volatile. As described under "Hedging Activities" below, we use commodity price hedging instruments to reduce our exposure to oil price fluctuations. The following are comparative average oil prices for the last three years:

	Year Ended December 31		
(per Bbl)	2007	2006	2005
Average NYMEX price	$ 72.39	$ 66.22	$ 56.57
Average realized sales price	$ 70.08	$ 60.96	$ 47.03
Average realized sales price excluding hedging	$ 68.68	$ 60.79	$ 52.28

At February 12, 2008, the average NYMEX oil price for the following 12 months was $91.91 per Bbl. After considering hedges in place as of February 15, 2008, we estimate that a $1.00 per barrel change in the average oil sales price would result in approximately a $7 million change in 2008 annual operating cash flow before income taxes.

Gulf of Mexico Hurricanes. In late August and September 2005, hurricanes in the Gulf of Mexico disrupted a significant portion of U.S. oil and gas production, leading to higher and more volatile commodity prices. The Company's field operations and production were substantially unaffected by these hurricanes. Production expense and development costs, however, increased throughout the industry because of storm damages and related supply shortages and higher insurance costs.

Hedging Activities. We may 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 consider hedging a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the full benefit of rising prices, management plans to continue its hedging strategy because of the benefits of predictable, stable cash flows.

In 2007, all hedging activities increased gas revenue by $658 million and oil revenue by $24 million. In 2006, all hedging activities increased gas revenue by $618 million and oil revenue by $3 million. In 2005, all hedging activities decreased gas revenue by $127 million and oil revenue by $75 million.

The following summarizes our 2008 NYMEX hedging positions under futures contracts and swap agreements as of February 2008, excluding basis adjustments.

Our average daily production was 1.67 Bcf of gas, 48,844 Bbls of oil and 14,462 Bbls of natural gas liquids in fourth quarter 2007. Prices to be realized for hedged production will be less than these NYMEX prices because of location, quality and other adjustments. See Note 8 to the Consolidated Financial Statements.

	Production Period	Mcf per Day	per Mcf
2008	January to March	1,100,000	$ 8.33
	April to December	1,200,000	$ 8.32

		Crude Oil	
	Production Period	Bbls per Day	Average NYMEX Price per Bbl
2008	January to December	30,000	$ 74.20

		Natural Gas Liquids	
	Production Period	Bbls per Day	Average Price per Bbl
2008	January to December	5,000	$ 44.22

Derivative Fair Value (Gain) Loss. We record in our income statements realized and unrealized derivative fair value gains and losses related to derivatives that do not qualify for hedge accounting, as well as the ineffective portion of hedge derivatives. We recorded net derivative fair value gains of $11 million in 2007, $102 million in 2006 and $13 million in 2005. Of these amounts, an $11 million gain in 2007, a $67 million gain in 2006 and a $1 million loss in 2005 was due to the ineffective portion of hedge derivatives. These ineffective hedge derivative gains and losses are primarily because of fluctuating oil and gas prices and their effect on hedges of production in areas without corresponding basis or location differential swap contracts.

Derivative fair value (gain) loss includes a net gain related to our Btu swap contracts of $16 million in 2006 and a net loss of $23 million in 2005. The remaining portion of these contracts was terminated as of February 28, 2006.

Unrealized derivative gains and losses associated with effective cash flow hedges are recorded in stockholders' equity as accumulated other comprehensive income (loss). At December 31, 2007, we have an unrealized pre-tax loss of $52 million in accumulated other comprehensive income (loss) related to the fair value of derivatives designated as cash flow hedges of natural gas, crude oil and natural gas liquids price risk. Based on December 31 mark-to-market prices, all of this fair value loss is expected to be reclassified into earnings in 2008. The actual reclassification to earnings will be based on mark-to-market prices at contract settlement date.

Stock-Based Compensation. Stock compensation totaled $65 million in 2007, $63 million in 2006 and $34 million in 2005. Included in stock option expense in 2006 is $36 million related to options granted in the second quarter which were subject to accelerated vesting provisions upon retirement under employment agreements for certain employees. As required under SFAS No. 123R, stock option awards subject to such vesting provisions granted to retirement-eligible employees are expensed upon grant, rather than over the expected vesting period. As of December 31, 2007, stock compensation expense is expected to total $92 million in 2008, $46 million in 2009, and $21 million in 2010 related to all outstanding stock awards.

Hugoton Royalty Trust Distribution. In January 2006, the Board of Directors declared a dividend to common stockholders, consisting of all 21.7 million Hugoton Royalty Trust units owned by us. The dividend ratio of 0.047688 trust units for each common share outstanding was set on the record date of April 26, 2006. The units were distributed on May 12, 2006, when this dividend was recorded. We recorded this dividend at $614 million, or approximately $1.35 per common share, the fair market value of the units based on the May 12, 2006 average high and low New York Stock Exchange trade price of $28.31. After considering the cost of the trust units, we recorded a gain on distribution of $469 million before income tax.

Senior Note Offerings. In April 2005, we sold $400 million of 5.3% senior notes due June 2015. In March 2006, we sold $400 million of 5.65% senior notes due April 2016 and $600 million of 6.1% senior notes due April 2036. In July 2007, we sold $300 million of 5.9% senior notes due August 1, 2012, $450 million of 6.25% senior notes due August 1, 2017 and $500 million of 6.75% senior notes due August 1, 2037. In August 2007, we sold an additional $250 million of the 5.9% senior notes, $300 million of the 6.25% senior notes and $450 million of the 6.75% senior notes that constituted a further issuance of the senior notes issued in July 2007. Proceeds from the senior notes were used to fund property acquisitions and reduce bank debt.

Common Stock Transactions. In June 2007, we completed a public offering of 21.6 million common shares at $48.40 per share. After underwriting discount and other offering costs of $35 million, net proceeds of $1.0 billion were used to fund a portion of the acquisition of natural gas and oil properties from Dominion Resources, Inc.

In February 2008, we completed a public offering of 23 million common shares at $55.00 per share. After underwriting discount and other offering costs of $42 million, net proceeds of $1.2 billion were used to fund a portion of the $1.0 billion of property acquisitions expected to close in first quarter 2008 and to repay indebtedness under our commercial paper program.

terms to be determined at the time of sale. Net proceeds from the sale of such securities are to be used for general corporate purposes, including the reduction of bank debt.

In June 2006, we registered 3.2 million shares of our common stock, which were issued in the acquisition of Peak Energy Resources on June 30, 2006.

RESULTS OF OPERATIONS

2007 Compared to 2006

For the year 2007, net income was $1.7 billion compared with net income of $1.9 billion for 2006. Earnings for 2007 include the net after-tax effects of a $28 million non-cash derivative fair value loss. Earnings for 2006 include the net after-tax effects of a $295 million gain on the distribution of Hugoton Royalty Trust units, a $24 million non-cash derivative fair value gain and $34 million of income tax expense related to enactment of a State of Texas margin tax.

Revenues for 2007 were $5.5 billion, or 20% higher than 2006 revenues of $4.6 billion. Gas and natural gas liquids revenue increased $724 million, or 21%, because of a 23% increase in gas production, a 14% increase in natural gas liquids production and a 23% increase in natural gas liquids prices from an average price of $37.03 per Bbl in 2006 to $45.37 in 2007, partially offset by a 2% decrease in gas prices from an average of $7.69 per Mcf in 2006 to $7.50 in 2007 (see "Significant Events, Transactions and Conditions — Product Prices — Gas" above). Increased production was attributable to the 2007 acquisition and development program.

Oil revenue increased $202 million, or 20%, because of a 4% increase in production, primarily due to the 2007 acquisition and development program, and a 15% increase in oil prices from an average of $60.96 per Bbl in 2006 to $70.08 in 2007 (see "Significant Events, Transactions and Conditions — Product Prices — Oil" above).

Gas gathering, processing and marketing activities resulted in a net contribution of $19 million in 2007 compared to a net contribution of $45 million in 2006. The decreased net contribution was primarily due to higher costs.

Expenses for 2007 totaled $2.6 billion as compared with total 2006 expenses of $1.9 billion. Increased expenses are generally related to increased production from acquisitions and development and related Company growth. Production expense increased $124 million, or 25%, primarily because of increased overall production and higher maintenance costs. The per Mcfe production expense increase from $0.88 in 2006 to $0.93 in 2007 is primarily attributable to the increased maintenance costs. Taxes, transportation and other expense increased 19%, or $72 million, primarily because of higher product revenues. Taxes, transportation and other per Mcfe was $0.67 in both 2007 and 2006. An increase in transportation and other expense as a result of higher product prices was offset by lower production taxes and lower property taxes. The lower production taxes were primarily due to the benefit of increased gas volumes from new drill wells which were subject to reduced production tax rates. Exploration expense increased $30 million primarily because of increased seismic costs in South Texas and unsuccessful exploratory wells.

Depreciation, depletion and amortization (DD&A) increased $312 million, or 36% primarily because of increased production. On an Mcfe basis, DD&A increased 13% from $1.57 in 2006 to $1.78 in 2007 because of higher acquisition, development and facility costs.

General and administrative expense increased $42 million (22%). Of this increase, $2 million was the result of an increase in non-cash incentive award compensation. Included in 2006 non-cash incentive award compensation was $36 million related to options granted in the second quarter which were subject to accelerated vesting provisions upon retirement under employment agreements for certain employees. As required under SFAS No. 123R, stock option awards subject to such vesting provisions granted to retirement-eligible employees are expensed upon grant, rather than over the expected vesting period. Excluding this charge, non-cash incentive award compensation increased $38 million in 2007 primarily as a result of additional incentive award grants since last year as well as an increase in the fair value of each award granted. Increased general and administrative expense, excluding non-cash incentive award compensation, is primarily because of higher employee expenses related to Company growth. Excluding non-cash incentive award compensation, general and administrative expense per Mcfe increased 14% from $0.22 in 2006 to $0.25 in 2007.

The derivative fair value gain for 2007 was $11 million compared to $102 million in 2006. The 2007 gain is primarily related to the ineffective portion of hedge derivatives. The 2006 gain is primarily related to the ineffective portion of hedge derivatives as well as a $16 million gain on the final settlement of Btu swap contracts. See Note 7 to Consolidated Financial Statements.

Interest expense increased $70 million, or 39%, primarily because of a 43% increase in the weighted average borrowings to partially fund property acquisitions partially offset by higher interest income related to increased cash on hand and an increase in capitalized interest. Interest expense per Mcfe increased 19% from $0.32 in 2006 to $0.38 in 2007. The 2007 effective income tax rate was 36.0%, as compared with a 37.2% effective rate for 2006. Excluding the effect of the $34 million income tax expense related to a State of Texas margin tax, the effective tax rate for the 2006 period was 36.0%. The current portion of total income taxes was 31% in 2007 and 52% in 2006. Excluding the effect of the gain on the distribution of Hugoton Royalty Trust units, the current portion

2006 Compared to 2005

For the year 2006, net income was $1.9 billion compared with net income of $1.2 billion for 2005. Earnings for 2006 include the net after-tax effects of a $295 million gain on the distribution of Hugoton Royalty Trust units, a $24 million non-cash derivative fair value gain and $34 million of income tax expense related to enactment of a new State of Texas margin tax. Earnings for 2005 include the net after-tax effects of non-cash incentive compensation of $22 million, a $25 million non-cash derivative fair value gain and a gain of $6 million on the exchange of producing properties.

Revenues for 2006 were $4.6 billion, or 30% higher than 2005 revenues of $3.5 billion. Gas and natural gas liquids revenue increased $703 million, or 25%, because of a 15% increase in gas production and a 9% increase in gas prices from an average of $7.04 per Mcf in 2005 to $7.69 in 2006, as well as a 13% increase in natural gas liquids production and a 9% increase in natural gas liquids prices from an average price of $34.10 per Bbl in 2005 to $37.03 in 2006 (see "Significant Events, Transactions and Conditions — Product Prices — Gas" above). Increased production was attributable to the 2006 acquisition and development program.

Oil revenue increased $332 million, or 50%, because of a 15% increase in production, primarily due to the 2006 acquisition and development program, and a 30% increase in oil prices from an average of $47.03 per Bbl in 2005 to $60.96 in 2006 (see "Significant Events, Transactions and Conditions — Product Prices — Oil" above).

Gas gathering, processing and marketing activities resulted in a contribution of $45 million in both 2006 and 2005. In 2005, other revenues of $6 million were primarily related to a net gain on sale or exchange of producing properties. See Note 13 to Consolidated Financial Statements.

Expenses for 2006 totaled $1.9 billion as compared with total 2005 expenses of $1.6 billion. Increased expenses are generally related to increased production from acquisitions and development and related Company growth. Production expense increased $85 million, or 21%, primarily because of increased overall production, and higher labor, fuel, compression and maintenance costs. The per Mcfe production expense increase from $0.84 in 2005 to $0.88 in 2006 is primarily attributable to the increased maintenance and workover costs and the higher cost of electricity. Taxes, transportation and other expense, which is generally directly related to product revenue, increased 22%, or $66 million, primarily because of increased transportation and other expense related to higher product prices. Taxes, transportation and other per Mcfe increased 6% from $0.63 in 2005 to $0.67 in 2006 primarily due to increased transportation and other expense as a result of higher product prices. Exploration expense decreased $2 million primarily because of decreased seismic work in the Barnett Shale.

Depreciation, depletion and amortization (DD&A) increased $220 million, or 34%, primarily because of increased production. On an Mcfe basis, DD&A increased 16% from $1.35 in 2005 to $1.57 in 2006 because of higher acquisition, development and infrastructure costs.

General and administrative expense increased $34 million (22%). Excluding a $24 million decrease in non-cash performance and restricted share award compensation related to performance and restricted share grants to employees and a $53 million charge for expensing stock options related to the adoption of SFAS No. 123R in 2006, general and administrative expense increased $5 million (4%). Increased general and administrative expense is primarily because of higher employee expenses related to Company growth. Included in stock option expense in the 2006 period is $36 million related to options granted in the second quarter which were subject to accelerated vesting provisions upon retirement under employment agreements for certain employees. As required under SFAS No. 123R, stock option awards subject to such vesting provisions granted to retirement-eligible employees are expensed upon grant, rather than over the expected vesting period. Excluding stock compensation, general and administrative expense per Mcfe decreased 12% from $0.25 in 2005 to $0.22 in 2006.

The derivative fair value gain for 2006 was $102 million compared to $13 million in 2005. The 2006 gain is primarily related to the ineffective portion of hedge derivatives as well as a $16 million gain on the final settlement of Btu swap contracts. The 2005 gain is primarily because of a $37 million gain related to natural gas basis swap agreements not qualifying for hedge accounting, partially offset by losses on Btu swap contracts. See Note 7 to Consolidated Financial Statements.

Interest expense increased $27 million, or 18%, primarily because of a 14% increase in the weighted average borrowings to partially fund property acquisitions and a 10% increase in the weighted average interest rate due to increases in short-term rates. Interest expense per Mcfe increased 3% from $0.31 in 2005 to $0.32 in 2006.

The 2006 effective income tax rate was 37.2%, as compared with a 36.3% effective rate for 2005. Excluding the effect of the $34 million income tax expense related to a new State of Texas margin tax enacted during second quarter, the effective tax rate for the 2006 period was 36%. The lower rate in 2006 is because of the benefit of certain nonrecurring permanent tax over book differences which was partially offset by increased income taxes in states other than Texas. Because of increased profit in 2006 and greater utilization of net operating loss carryforwards in 2005, the current portion of total income tax expense increased from 37% in 2005 to 52% in 2006.

Our primary sources of liquidity are cash provided by operating activities, borrowings under either our revolving credit agreement, our other unsecured and uncommitted lines of credit or our commercial paper program, occasional proved property sales and private or 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 2008.

Cash provided by operating activities was $3.6 billion in 2007, compared with cash provided by operating activities of $2.9 billion in 2006 and $2.1 billion in 2005. Increased cash provided by operating activities from 2006 to 2007 and from 2005 to 2006 was primarily because of increased production from acquisitions and development activity, and higher price realizations in 2006 compared to 2005. Cash provided by operating activities was decreased by changes in operating assets and liabilities of $72 million in 2007 and $158 million in 2005 and was increased by changes in operating assets and liabilities of $5 million in 2006. Changes in operating assets and liabilities are primarily the result of timing of cash receipts and disbursements. Cash provided by operating activities was also reduced by exploration expense (net of dry hole expense beginning in 2006) of $31 million in 2007, $13 million in 2006 and $24 million in 2005. Cash provided by operating activities is largely dependent upon the prices received for oil and gas production. As of February 2008, we have hedged approximately 65% of our 2008 projected gas production, about 60% of our projected 2008 crude oil production and about 30% of our projected 2008 natural gas liquids production. See "Significant Events, Transactions and Conditions — Product Prices" above.

Financial Condition

Total assets increased 47% from $12.9 billion at December 31, 2006 to $18.9 billion at December 31, 2007, primarily because of Company growth related to acquisitions and development. As of December 31, 2007, total capitalization was $14.3 billion, of which 44% was long-term debt. Capitalization at December 31, 2006 was $9.3 billion, of which 37% was long-term debt. The increase in the debt-to-capitalization ratio from year-end 2006 to 2007 is primarily because of increased borrowings to partially fund property acquisitions.

Working Capital

We generally maintain low cash and cash equivalent balances because we use available funds to reduce either bank debt or borrowings under our commercial paper program. Short-term liquidity needs are satisfied by either bank commitments under our loan agreements or our commercial paper program (see "Financing" below). Because of this, and since our principal source of operating cash flows (i.e., proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. Working capital declined from $345 million at December 31, 2006 to a negative position of $250 million at December 31, 2007. Excluding the effects of derivative fair value and deferred tax current assets and liabilities, working capital decreased $71 million from a negative position of $159 million at December 31, 2006 to a negative position of $230 million at December 31, 2007. This decrease is because of increased accounts payable and accrued liabilities primarily related to increased production and drilling liabilities partially offset by increased accounts receivable related to increased revenues and increased current income taxes receivable. Any cash settlement of hedge derivatives should generally be offset by increased or decreased cash flows from our sales of related production. Therefore, we believe that most of the changes in derivative fair value assets and liabilities are offset by changes in value of our oil and gas reserves. This offsetting change in value of oil and gas reserves, however, is not recorded in the financial statements.

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 55 days. Any interim cash needs are funded by borrowings under either our revolving credit agreement, our other unsecured and uncommitted lines of credit, or our commercial paper program. None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date.

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. We currently have the majority of our credit exposure with several A- or better rated integrated energy companies. Financial and commodity-based futures and swap contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions, and we have master netting agreements with counterparties that provide for offsetting payables against receivables from separate derivative contracts. Letters of credit or other appropriate forms of security are obtained as considered necessary to limit risk of loss.

Financing

On December 31, 2007, we had no borrowings under our revolving credit agreement with commercial banks, and we had available borrowing capacity of $1.2 billion net of our commercial paper borrowings. In February 2008, we amended this agreement to, among other things, increase the borrowing capability to $2.5 billion and to extend the maturity date to April 1, 2013. We have is for a period of 90 days or more. We also incur a commitment fee on unused borrowing commitments, which is 0.09%. The agreement requires us to maintain a debt-to-total capitalization ratio of not more than 65%. We use the facility for general corporate purposes and as a backup facility for our commercial paper program (see below). We did not make any borrowings under our revolving credit facility during 2007.

In February 2008, we increased our commercial paper program availability to $2.5 billion. Borrowings under the commercial paper program reduce our available capacity under the revolving credit facility on a dollar-for-dollar basis. The commercial paper borrowings may have terms up to 397 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. On December 31, 2007, borrowings were $772 million at an interest rate of 5.38%.

In February 2008, we also amended our $300 million term loan credit agreement to increase outstanding borrowings to $500 million and to extend the maturity date to April 1, 2013. In March 2007, we amended our $300 million term loan credit agreement to conform its covenants and pricing to our bank revolving credit agreement and to extend the maturity.

Additionally in February 2008, we entered into a new five-year unsecured term loan agreement with The Royal Bank of Scotland Finance (Ireland) that provides for a maximum loan amount of $100 million available in a single advance that matures February 5, 2013. The interest rate is currently based on LIBOR plus 0.34%, and interest is paid at least quarterly. Other terms and conditions are substantially the same as our term loan. The proceeds were used for general corporate purposes.

We have unsecured and uncommitted lines of credit with commercial banks totaling $300 million. As of December 31, 2007, there were no borrowings under these lines.

In February 2008, we completed a public offering of 23 million common shares at $55.00 per share. After underwriting discount and other offering costs of $42 million, net proceeds of $1.2 billion were used to fund a portion of the $1.0 billion of property acquisitions expected to close in first quarter 2008 and to repay indebtedness under our commercial paper program.

In June 2007, we completed a public offering of 21.6 million common shares at $48.40 per share. After underwriting discount and other offering costs of $35 million, net proceeds of $1.0 billion were used to fund a portion of the acquisition of natural gas and oil properties from Dominion Resources, Inc.

In July 2007, we sold $300 million of 5.9% senior notes due August 1, 2012, $450 million of 6.25% senior notes due August 1, 2017 and $500 million of 6.75% senior notes due August 1, 2037. In August 2007, we sold an additional $250 million of the 5.9% senior notes, $300 million of the 6.25% senior notes and $450 million of the 6.75% senior notes that constituted a further issuance of the senior notes issued in July 2007. Together, the 5.9% senior notes were issued at 100.585% of par to yield 5.761% to maturity. The 6.25% senior notes were issued at 100.419% of par to yield 6.193% to maturity. The 6.75% senior notes were issued at 100.022% of par to yield 6.748% to maturity. Interest is payable on each series of notes on February 1 and August 1 of each year, beginning February 1, 2008. Net proceeds of $2.24 billion were used to fund a portion of the acquisition of properties from Dominion Resources, Inc. and to pay down outstanding commercial paper borrowings.

Possible Formation of a Master Limited Partnership

In conjunction with our announcement of the Dominion acquisition, we disclosed our intent to review our entire portfolio of producing properties, including those acquired in the acquisition, for selective inclusion in a potential master limited partnership to be formed by us with an initial capitalization of over $500 million. In February 2008, we announced that we would not pursue the formation of a master limited partnership at this time.

Capital Expenditures

In 2007, exploration and development cash expenditures totaled $2.7 billion compared with $2.1 billion in 2006. We have budgeted $2.6 billion for the 2008 development and exploration program and an additional $400 million for the construction of pipeline infrastructure and compression and processing facilities. As we have done historically, we expect to fund the 2008 development program with cash flow from operations. 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.

Raw material shortages and strong global demand for steel have caused prices to remain high. In response, we maintain a large tubular inventory and have contracts with our suppliers to support our development program. While we expect to acquire adequate supplies to complete our development program, a further tightening of steel supplies could restrain the program, limiting production growth and increasing development costs.

Although drilling rigs have been in short supply throughout the industry, we have secured or contracted to secure the rigs necessary to support our current drilling program.

and by proceeds from the February 2008 common stock offering and are subject to typical post-closing adjustments. We plan to actively review additional acquisition opportunities during 2008. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, our commercial paper program, issuance of public or private debt or equity, or asset sales. Other than the requirement for us to maintain a debt-to-total capitalization ratio of not more than 65%, there are no restrictions under our revolving credit agreement that would affect our ability to use our remaining borrowing capacity.

To date, we have not spent significant amounts to comply with environmental or safety regulations, and we do not expect to do so during 2008. 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 $0.04 per common share for the first three quarters of 2005, $0.06 per common share for fourth quarter 2005 and the first three quarters of 2006, $0.072 per common share for fourth quarter 2006 and $0.096 per common share for the first three quarters of 2007. In November 2007, the Board of Directors declared a five-for-four stock split of its common stock and increased its quarterly dividend to $0.12 per common share for the fourth quarter 2007, effecting a 25% dividend increase. On February 19, 2008, the Board of Directors declared a first quarter 2008 dividend of $0.12 per common share.

In January 2006, the Board of Directors declared a dividend to common stockholders, consisting of all 21.7 million Hugoton Royalty Trust units owned by us. The dividend ratio of 0.047688 trust units for each common share outstanding was set on the record date of April 26, 2006. The units were distributed on May 12, 2006, when this dividend was recorded at approximately $1.35 per common share, based on the fair market value of the units on that date.

Our ability to pay dividends is dependent upon our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters our Board deems relevant.

Off-Balance Sheet Arrangements

We do not have any investments in unconsolidated entities or persons that could materially affect the liquidity or the availability of capital resources. Under the terms of some of our operating leases for compressors, airplanes and vehicles, we have various residual value guarantees and other payment provisions upon our election to return the equipment under certain specified conditions. Guarantees related to these leases are not material. The only material off-balance sheet arrangements that we have entered into are those disclosed in the following table of contractual obligations and commitments.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The following summarizes our significant obligations and commitments to make future contractual payments as of December 31, 2007. We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt or losses.

		Payments Due by Year					
(in millions)	Total	2008	2009	2010	2011	2012	After 2012
Long-term debt	$ 6,320	$ –	$ –	$ –	$ –	$ 1,975	$ 4,345
Operating leases	92	24	21	19	13	7	8
Drilling contracts	218	142	61	15	–	–	–
Purchase commitments	173	147	26	–	–	–	–
Transportation contracts	999	117	122	121	116	107	416
Derivative contract liabilities at December 31, 2007 fair value	243	239	3	1	–	–	–
Total	$ 8,045	$ 669	$ 233	$ 156	$ 129	$ 2,089	$ 4,769

Long-Term Debt. At December 31, 2007, borrowings were $772 million under our commercial paper program. Because we had both the intent and ability to refinance the balance due with borrowings under our credit facility due in April 2012, the $772 million outstanding under the commercial paper program is reflected in the table above as due in 2012. Borrowings of $300 million under our term loan are due in April 2012, and our senior notes, totaling $5.2 billion at December 31, 2007, are due 2012 through 2037. In February 2008, we extended the maturities of both our credit facility and our term loan to April 2013. For further information regarding long-term debt, see Note 3 to Consolidated Financial Statements.

any deficiencies at a specified reservation fee rate. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under these firm transportation contracts, therefore avoiding payment for deficiencies.

In December 2006, we entered into a ten-year firm transportation contract that commences upon completion of a new 502-mile pipeline spanning from southeast Oklahoma to east Alabama. Upon the pipeline's completion, currently expected in first quarter 2009, we will transport gas volumes for a minimum transportation fee of $2 million per month plus fuel not to exceed 1.2% of the sales price, depending on receipt point and other conditions. The potential effect of this agreement is not included in the above summary of our transportation contract commitments since our commitment is contingent upon completion of the pipeline.

Derivative Contracts. We have entered into futures contracts and swaps to hedge our exposure to natural gas, oil and natural gas liquids price fluctuations. As of December 31, 2007, the market prices generally exceeded fixed prices specified by these contracts, resulting in a derivative fair value net current liability of $40 million and a net long-term liability of $4 million. If market prices are higher than the contract prices when the cash settlement amount is calculated, we are required to pay the contract counterparties. As of December 31, 2007, the current liability related to such contracts was $239 million and the noncurrent liability was $4 million. While such payments generally will be funded by higher prices received from the sale of our production, production receipts may be received as much as 55 days after payment to counterparties and can result in draws on our revolving credit facility, our other unsecured and uncommitted lines of credit or our commercial paper program. See Note 7 to Consolidated Financial Statements.

POST-RETIREMENT PLANS

We have a retiree medical plan that provides retired employees and directors with health care benefits similar to those provided employees. Employees are eligible to receive benefits when their combined age and years of qualified service total 60, with a minimum age of 50 and a minimum of 10 years of service. However, employees who were eligible under the previous eligibility rules were grandfathered in under the previous rules which allowed them to receive benefits when their combined age and years of qualified service totaled 60, with a minimum age of 45 and a minimum of five years of service. Directors are still eligible to receive benefits when their combined age and years of qualified service total 60, with a minimum age of 45 and a minimum of five years of service. Otherwise, retirement benefits are only provided through our defined contribution 401(k) plan. Post-retirement medical benefits are not prefunded but are paid when incurred. Our periodic benefit cost recorded for 2007 was $2 million and is expected to be approximately $3 million in 2008. Future benefit costs will be affected by fluctuations in interest rates and health care cost trends. We do not currently anticipate that retiree medical plan costs will be significant in relation to the Company's future financial position, results of operations or cash flows.

RELATED PARTY TRANSACTIONS

A firm, affiliated with one of our nonemployee directors, has performed property acquisition advisory services for the Company. In February 2005, this firm was acquired by another company which continues to perform property acquisition advisory services for us, and a division of the company also performed co-manager services on our June 2007 common stock offering and our July and August 2007, March 2006 and April 2005 senior note offerings. We paid this firm total fees of $3.4 million in 2007, $78,500 in 2006 and $5.0 million in 2005, and there were no amounts payable at December 31, 2007 or 2006. In February 2008, this firm served as one of 24 co-managers on our common stock offering.

In February 2007, in recognition of the Chairman and Chief Executive Officer of the Company and as part of a charitable giving program to support higher education, the Board of Directors approved a conditional contribution of $6.8 million to assist in building an athletics and academic center at Baylor University. This contribution is to be paid in two equal installments of $3.4 million. The first payment was made May 2007 and the second is expected to be paid in the first half of 2008. Since this is a conditional contribution, the first payment is included as general and administrative expense in 2007. However, the second payment will not be made and included in general administrative expense until such time as the condition is satisfied. Concurrently, our Chairman and Chief Executive Officer, made a $3.2 million pledge for the same project. In return for these contributions, the Company and Mr. Simpson obtained naming rights for the building and certain facilities within the building.

In November 2007, the Board of Directors approved and we paid our Chairman and Chief Executive Officer $150,000 for an easement across his property in North Texas. The easement was for approximately 10,000 feet at the standard easement rate in the area of $15 per foot.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Oil and gas 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.

In accordance with Statement of Financial Accounting Standards No. 144, we evaluate possible impairment of producing properties when conditions indicate that the properties may be impaired. Such conditions include a significant decline in product prices which we believe to be other than temporary or a significant downward revision in estimated proved reserves for a field or area. An impairment provision must be recorded to adjust the net book value of the property to its estimated fair value if the net book value exceeds the estimated future net cash flows from the property. The estimated fair value of the property is generally calculated as the discounted present value of future net cash flows. Our estimates of cash flows are based on the latest available proved reserve and production information and management's estimates of future product prices and costs, based on available information such as forward strip prices and industry forecasts and analysis.

The impairment assessment process is primarily dependent upon the estimate of proved reserves. Any overstatement of estimated proved reserve quantities would result in an overstatement of estimated future net cash flows, which could result in an understated assessment of impairment. The subjectivity and risks associated with estimating proved reserves are discussed under "Oil and Gas Reserves" below. Prediction of product prices is subjective since prices are largely dependent upon supply and demand resulting from global and national conditions generally beyond our control. However, management's assessment of product prices for purposes of impairment is consistent with that used in its business plans and investment decisions. While there is judgment involved in management's estimate of future product prices, the potential impact on impairment is not currently significant since current and projected product prices are substantially higher than our net acquisition and development costs per Mcfe. Because of this, our historical impairment of producing properties has been limited to a $2 million provision in 1998. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impracticable to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

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, including evaluations and extrapolations of well flow rates and reservoir pressure. 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.

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

Depreciation, depletion and amortization of producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. While total DD&A expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in timing of when DD&A expense is recognized. Downward revisions of proved reserves result in an acceleration of DD&A expense, while upward revisions tend to lower the rate of DD&A expense recognition. As shown in Note 15 to the Consolidated Financial Statements, net upward revisions occurred to proved reserves on an Mcfe basis in 2007 and 2005, resulting in a decrease of DD&A expense of approximately 1%, or $13 million in 2007 and 2%, or $10 million, in 2005. Net downward revisions of proved reserves on an Mcfe basis occurred in 2006, resulting in an increase in DD&A expense of approximately 1%, or $8 million in 2006. Based on proved reserves at December 31, 2007, we estimate that a 1% change in proved reserves would increase or decrease 2008 DD&A expense by approximately $13 million.

During 2007, development and exploration activities resulted in extensions, additions, discoveries and net revisions of proved reserves that were 308% of our 2007 production. Over the last five years, our proved reserve extensions, additions, discoveries and net revisions averaged 262% of our production for this period. Our proved reserve extensions, additions and discoveries in 2007 included an increase of 1.5 Tcfe in proved undeveloped reserves, or approximately 75% of our total extensions, additions and discoveries. The remaining extensions, additions and discoveries were proved developed reserves. Over the past five years, approximately 73% of our proved reserves extensions, additions and discoveries were proved undeveloped reserves. These proved undeveloped reserve extensions, additions and discoveries were generally reclassified to proved developed reserves within three years. Development of our proved undeveloped reserves is not subject to significant uncertainties such as regulatory approvals, and we believe that we have adequate resources to develop these reserves, dependent on commodity prices not declining significantly.

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.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. For example, as we analyze actual plugging and abandonment information, we may revise our estimates of current costs, the assumed annual inflation of these costs and/or the assumed productive lives of our wells. During 2007, we revised our existing estimated asset retirement obligation by $39 million, or approximately 13% of the asset retirement obligation at December 31, 2006, based on a review of current plugging and abandonment costs. Over the past four years, revisions to the estimated asset retirement obligation averaged approximately 12% of the asset retirement obligation at the beginning of the year. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Commodity Prices and Risk Management

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

We attempt to reduce our price risk on a portion of our production 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 may not be able to realize the full benefit of rising prices. These contracts also expose us to credit risk of nonperformance by the contract counterparties, all of which are major investment grade financial institutions. We attempt to limit our credit risk by obtaining letters of credit or other appropriate forms of security.

While our price risk management activities decrease the volatility of cash flows, they may obscure our reported financial condition. As required under U.S. generally accepted accounting principles, we record derivative financial instruments at their fair value, representing projected gains and losses to be realized upon settlement of these contracts in subsequent periods when related production occurs. These gains and losses are generally offset by increases and decreases in the market value of our proved reserves, which are not reflected in the financial statements. Derivatives that provide effective cash flow hedges are designated as hedges, and, to the extent the hedge is determined to be effective, we defer related unrealized fair value gains and losses in accumulated other comprehensive income (loss) until the hedged transaction occurs. See "Derivatives" under Note 1 to Consolidated Financial Statements regarding our accounting policy related to derivatives.

See also "Commodity Price Risk" under Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for the effect of price changes on derivative fair value gains and losses.

ACCOUNTING PRONOUNCEMENTS

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, was issued. SFAS No. 157 provides guidance for using fair value to measure assets and liabilities. It applies whenever other standards require or permit assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. In November 2007, the effective date was deferred for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value on a recurring basis. The provisions of SFAS No. 157 that were not deferred are effective for financial statements issued for

In February 2007, SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115,* was issued. SFAS No. 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of SFAS No. 159, effective January 1, 2008, did not have a significant effect on reported financial position or earnings.

In December 2007, SFAS No. 141R, *Business Combinations,* was issued. Under SFAS No. 141R, a company is required to recognize the assets acquired, liabilities assumed, contractual contingencies, and any contingent consideration measured at their fair value at the acquisition date. It further requires that research and development assets acquired in a business combination that have no alternative future use to be measured at their acquisition-date fair value and then immediately charged to expense, and that acquisition-related costs are to be recognized separately from the acquisition and expensed as incurred. Among other changes, this statement also requires that "negative goodwill" be recognized in earnings as a gain attributable to the acquisition, and any deferred tax benefits resultant in a business combination are recognized in income from continuing operations in the period of the combination. SFAS No. 141R is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning after December 15, 2008. The effect of adopting SFAS No. 141R has not been determined, but it is not expected to have a significant effect on our reported financial position or earnings.

In December 2007, SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51,* was issued. SFAS No. 160 amends ARB 51 to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. Among other requirements, this statement requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS No. 160 is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2008. The effect of adopting SFAS No. 160 is not expected to have an effect on our reported financial position or earnings.

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. Our net gas imbalance receivable of $1 million at December 31, 2007 was reported in the balance sheet as a $1 million net current receivable. At December 31, 2006, our net gas imbalance payable of $2 million was reported in the balance sheet as a $3 million net current receivable and a $5 million net long-term payable.

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 in total or by region, capital budget, cash flow, drilling activity, drilling locations, the number of wells to be drilled, worked over or recompleted in total or by region, acquisition and development activities and funding thereof, production and reserve growth, pricing differentials, reserve potential, operating costs, operating margins, production activities, oil, gas and natural gas liquids reserves and prices, hedging activities and the results thereof, liquidity, debt repayment, unused borrowing capacity, estimated stock award vesting periods, completion of pipelines and processing facilities, regulatory matters, competition, and value of non-cash dividends. 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 in Item 1A, Risk Factors.

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 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, crude oil and natural gas liquids 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. Risk management programs using derivatives must be authorized by the Chairman of the Board and the Senior Executive Vice President and Chief of Staff. These programs are also reviewed quarterly by our internal risk management committee and annually by the Board of Directors.

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

INTEREST RATE RISK

We are exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At December 31, 2007, our variable rate debt had a carrying value of $1.1 billion, which approximated its fair value, and our fixed rate debt had a carrying value of $5.2 billion and an approximate fair value of $5.4 billion. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk. This is accomplished through a mix of bank debt with short-term variable rates and fixed rate senior and subordinated debt, as well as the occasional use of interest rate swaps.

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

(in millions)	Carrying Amount	Fair Value (a)	Hypothetical Change in Fair Value
December 31, 2007 Long-term debt	$(6,320)	$(6,438)	$422
December 31, 2006 Long-term debt	$(3,451)	$(3,427)	$220

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

COMMODITY PRICE RISK

We hedge a portion of our price risks associated with our natural gas, crude oil and natural gas liquid sales. As of December 31, 2007, our outstanding futures contracts and swap agreements had a net fair value loss of $44 million. The following table shows the fair value of our derivative contracts and the hypothetical change in fair value that would result from a 10% change in commodities prices or basis prices at December 31, 2007. The hypothetical change in fair value could be a gain or a loss depending on whether prices increase or decrease.

(in millions)	Fair Value	Hypothetical Change in Fair Value
Natural gas futures and sell basis swap agreements	$ 185	$253
Natural gas purchase basis swap agreements	$ –	$ 1
Crude oil futures and differential swaps	$ (207)	$101
Natural gas liquids futures	$ (22)	$ 10

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 (loss) 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. None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date.

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

There have been no 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, 2007.

Item 9A.

Controls and Procedures

a) Evaluation of Disclosure Controls and Procedures

We performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15 and 15d-15 as of the end of the period covered by this report. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in our periodic filings with the Securities and Exchange Commission and that our disclosure controls and procedures are effective to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized and reported within the specific time periods. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected.

b) Management's Report on Internal Control over Financial Reporting

Our management's report on internal control over financial reporting is set forth in Item 8 of this Annual Report on Form 10-K and is incorporated by reference herein.

c) Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting during the quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B.

Other Information

None.

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 or is included below, the information called for by Items 10 through 14 is incorporated by reference to the Company's Notice of Annual Meeting and Proxy Statement to be filed with the Securities and Exchange Commission no later than April 30, 2008.

Item 10.

Directors, Executive Officers and Corporate Governance

We have a Code of Business Conduct and Ethics that applies to all directors, officers and employees, including the chief executive officer and senior financial officers. We also have a Code of Ethics for the Chief Executive Officer and Senior Financial Officers. You can find our Code of Business Conduct and Ethics and our Code of Ethics for the Chief Executive Officer and Senior Financial Officers on our web site at http://www.xtoenergy.com. You can also obtain a free copy of these materials by contacting us at 810 Houston Street, Fort Worth, Texas 76102, Attn: Corporate Secretary. Any amendments to or waivers from these codes that apply to our executive officers will be posted on the Company's web site or by other appropriate means in accordance with the rules of the Securities and Exchange Commission.

Item 11.

Executive Compensation

Item 12.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Item 13.

Certain Relationships and Related Transactions, and Director Independence

Item 14.

Principal Accountant Fees and Services

Exhibits and Financial Statement Schedules

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

2. Financial Statement Schedules:

All 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) Exhibits

See Index to Exhibits at page 73 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.

(in millions, except shares)	2007	2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ –	$ 5
Accounts receivable, net	852	656
Derivative fair value	199	804
Current income tax receivable	118	66
Deferred income tax benefit	20	–
Other	98	54
Total Current Assets	1,287	1,585
Property and Equipment, at cost — successful efforts method:		
Proved properties	18,671	12,369
Unproved properties	1,050	414
Other	1,376	799
Total Property and Equipment	21,097	13,582
Accumulated depreciation, depletion and amortization	(3,897)	(2,758)
Net Property and Equipment	17,200	10,824
Other Assets:		
Derivative fair value	–	56
Acquired gas gathering contracts, net of amortization	112	121
Goodwill	215	215
Other	108	84
Total Other Assets	435	476
TOTAL ASSETS	$ 18,922	$ 12,885
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 1,264	$ 912
Payable to royalty trusts	30	23
Derivative fair value	239	37
Deferred income tax payable	–	263
Other	4	5
Total Current Liabilities	1,537	1,240
Long-term Debt	6,320	3,451
Other Long-term Liabilities:		
Derivative fair value	4	1
Deferred income taxes payable	2,610	1,978
Asset retirement obligation	450	303
Other	60	47
Total Other Long-term Liabilities	3,124	2,329
Commitments and Contingencies (Note 6)		
Stockholders' Equity:		
Common stock ($0.01 par value, 1,000,000,000 shares authorized, 490,434,003 and 464,342,418 shares issued)	5	5
Additional paid-in capital	3,172	2,057
Treasury stock, at cost (5,140,230 and 4,899,840 shares)	(134)	(125)
Retained earnings	4,938	3,442
Accumulated other comprehensive income (loss)	(40)	486
Total Stockholders' Equity	7,941	5,865
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 18,922	$ 12,885

See accompanying notes to consolidated financial statements.

(in millions, except per share data)	Year Ended December 31 2007	2006	2005
REVENUES			
Gas and natural gas liquids	$4,214	$3,490	$2,787
Oil and condensate	1,204	1,002	670
Gas gathering, processing and marketing	100	86	56
Other	(5)	(2)	6
Total Revenues	5,513	4,576	3,519
EXPENSES			
Production	615	491	406
Taxes, transportation and other	444	372	306
Exploration	52	22	24
Depreciation, depletion and amortization	1,187	875	655
Accretion of discount in asset retirement obligation	22	16	12
Gas gathering and processing	81	41	11
General and administrative	231	189	155
Derivative fair value (gain) loss	(11)	(102)	(13)
Total Expenses	2,621	1,904	1,556
OPERATING INCOME	2,892	2,672	1,963
OTHER (INCOME) EXPENSE			
Gain on distribution of royalty trust units	–	(469)	–
Interest expense, net	250	180	153
Total Other (Income) Expense	250	(289)	153
INCOME BEFORE INCOME TAX	2,642	2,961	1,810
INCOME TAX EXPENSE			
Current	292	572	243
Deferred	659	529	415
Total Income Tax Expense	951	1,101	658
NET INCOME	$1,691	$1,860	$1,152
EARNINGS PER COMMON SHARE			
Basic	$ 3.58	$ 4.08	$ 2.57
Diluted	$ 3.53	$ 4.02	$ 2.52
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	471.9	456.1	448.1

See accompanying notes to consolidated financial statements.

(in millions)	2007	2006	2005
	Year Ended December 31		
OPERATING ACTIVITIES			
Net income	$ 1,691	$ 1,860	$ 1,152
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,187	875	655
Accretion of discount in asset retirement obligation	22	16	12
Non-cash incentive compensation	65	63	34
Dry hole expense	21	9	-
Deferred income tax	659	529	415
Gain on distribution of royalty trust units	-	(469)	-
Non-cash derivative fair value (gain) loss	43	(39)	(39)
Other non-cash items	23	10	23
Changes in operating assets and liabilities, net of effects of acquisitions of corporations (a)	(72)	5	(158)
Cash Provided by Operating Activities	3,639	2,859	2,094
INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	1	6	17
Property acquisitions, including acquisitions of corporations	(4,012)	(616)	(1,407)
Development costs, capitalized exploration costs and dry hole expense	(2,668)	(2,047)	(1,304)
Other property and asset additions	(666)	(379)	(214)
Cash Used by Investing Activities	(7,345)	(3,036)	(2,908)
FINANCING ACTIVITIES			
Proceeds from long-term debt	7,293	5,719	3,825
Payments on long-term debt	(4,433)	(5,377)	(2,977)
Net proceeds from common stock offering	1,009	-	-
Dividends	(170)	(109)	(67)
Senior note and debt offering costs	(18)	(9)	(5)
Proceeds from exercise of stock options and warrants	33	24	73
Payments upon exercise of stock options	(57)	(46)	(20)
Excess tax benefit on exercise of stock options	57	50	-
Purchases of treasury stock and other	(13)	(72)	(23)
Cash Provided by Financing Activities	3,701	180	806
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5)	3	(8)
Cash and Cash Equivalents, January 1	5	2	10
Cash and Cash Equivalents, December 31	$ -	$ 5	$ 2
(a) Changes in Operating Assets and Liabilities			
Accounts receivable	$ (198)	$ (12)	$ (258)
Other current assets	(85)	(16)	(47)
Other operating assets and liabilities	(9)	(12)	(3)
Current liabilities	220	45	150
	$ (72)	$ 5	$ (158)

See accompanying notes to consolidated financial statements.

(in millions, except per share amounts)	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balances, December 31, 2004	$ 4	$ 1,409	$ (25)	$ 1,240	$ (29)	$ 2,599
Net income	–	–	–	1,152	–	1,152
Change in hedge derivative fair value, net of applicable income tax of $27	–	–	–	–	(48)	(48)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income (loss), net of applicable income tax of $81	–	–	–	–	145	145
Comprehensive income						1,249
Issuance/vesting of performance shares	–	33	(14)	–	–	19
Stock option exercises, including income tax benefits	–	75	–	–	–	75
Issuance of common stock and warrants for acquisition of corporation	1	347	–	–	–	348
Common stock dividends ($0.18 per share)	–	–	–	(81)	–	(81)
Balances, December 31, 2005	5	1,864	(39)	2,311	68	4,209
Net income	–	–	–	1,860	–	1,860
Change in hedge derivative fair value, net of applicable income tax of $473	–	–	–	–	810	810
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income (loss), net of applicable income tax of $225	–	–	–	–	(390)	(390)
Adjustment related to initial recognition of funded status of post-retirement health plan, net of applicable income tax of $1	–	–	–	–	(2)	(2)
Comprehensive income						2,278
Issuance/vesting of stock awards	–	10	(3)	–	–	7
Expensing of stock options	–	53	–	–	–	53
Stock option and warrant exercises, including income tax benefits	–	28	–	–	–	28
Treasury stock purchases	–	–	(83)	–	–	(83)
Issuance of common stock for acquisition of corporation	–	102	–	–	–	102
Fair value of royalty trust unit distribution ($1.35 per share)	–	–	–	(614)	–	(614)
Common stock dividends ($0.252 per share)	–	–	–	(115)	–	(115)
Balances, December 31, 2006	5	2,057	(125)	3,442	486	5,865
Net income	–	–	–	1,691	–	1,691
Change in hedge derivative fair value, net of applicable income tax of $49	–	–	–	–	(77)	(77)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income (loss), net of applicable income tax of $257	–	–	–	–	(444)	(444)
Adjustment related to recognition of funded status of post-retirement health plan, net of applicable income tax of $3	–	–	–	–	(5)	(5)
Comprehensive income						1,165
Issuance/vesting of stock awards, including income tax benefits	–	26	(9)	–	–	17
Expensing of stock options	–	42	–	–	–	42
Stock option and warrant exercises, including income tax benefits	–	38	–	–	–	38
Common stock offering	–	1,009	–	–	–	1,009
Common stock dividends ($0.408 per share)	–	–	–	(195)	–	(195)
Balances, December 31, 2007	$ 5	$ 3,172	$ (134)	$ 4,938	$ (40)	$ 7,941

See accompanying notes to consolidated financial statements.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

The accompanying consolidated financial statements include the financial statements of XTO Energy Inc. and all of its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in 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 15, 2005 and the five-for-four stock split effected on December 13, 2007.

We are an independent oil and gas company with production and exploration concentrated in the southwestern and central United States. We also gather, process and market gas, transport and market oil and conduct other activities directly related to our oil and gas producing activities.

Property and Equipment

We follow the successful efforts method of accounting, capitalizing costs of successful exploratory wells and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. A significant portion of the property costs reflected in the accompanying consolidated balance sheets are from acquisitions of proved properties from other oil and gas companies. Proved properties balances include costs of $813 million at December 31, 2007 and $713 million at December 31, 2006 related to wells in process of drilling. Successful drill well costs are transferred to proved properties generally within one month of the well completion date. Inventory held for future use on our producing properties totaled $60 million at December 31, 2007 and $37 million at December 31, 2006, and is included in other current assets on the consolidated balance sheet.

Depreciation, depletion and amortization of proved 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 either the unit-of-production method for assets associated with specific reserves or the straight-line method over estimated useful lives which range from 3 to 40 years. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

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

In December 2004, the Financial Accounting Standards Board issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29*, which provides that all nonmonetary asset exchanges that have commercial substance must be measured based on the fair value of the assets exchanged, and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion No. 29 previously exempted exchanges of similar productive assets from fair value accounting, subject to recording an impairment loss. We adopted the provisions of SFAS No. 153 beginning July 1, 2005, and, based on the fair value of properties exchanged, we recognized a $10 million gain on the exchange of nonmonetary assets during 2005. See Note 13.

Asset Retirement Obligation

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 provides that, if the fair value for asset retirement obligation can be reasonably estimated, the liability should be recognized in the period when it is incurred. Oil and gas producing companies incur this liability upon acquiring or drilling a well. Under the method prescribed by SFAS No. 143, the retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to proved properties on the balance sheet. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. See Note 5.

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 owned 54.3% of Hugoton Royalty Trust, which is the portion we retained following our sale of units in 1999 and 2000. In January 2006, the Board of Directors declared a dividend to common stockholders, consisting of all 21.7 million Hugoton Royalty Trust units owned by us. The dividend ratio of 0.047688 trust units for each common share outstanding was set on the record date of April 26, 2006. The units were distributed on May 12, 2006, when this dividend was recorded. We recorded this dividend at $614 million, or approximately $1.35 per common share, the fair market value of the units based on the May 12, 2006 average high and low New York Stock Exchange trade price of $28.31. After considering the cost of the trust units, we recorded a gain on distribution of $469 million before income tax.

Amounts due the trusts are deducted from our revenues, taxes, production expenses and development costs.

Cash and Cash Equivalents

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

Income Taxes

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

Effective January 1, 2007, we adopted the provisions of FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—An Interpretation of FASB Statement No. 109.* FIN No. 48 clarifies financial statement recognition and disclosure requirements for uncertain tax positions taken or expected to be taken in a tax return. Financial statement recognition of the tax position is dependent on an assessment of a 50% or greater likelihood that the tax position will be sustained upon examination, based on the technical merits of the position. Any interest and penalties related to uncertain tax positions are recorded as interest expense and general and administrative expense, respectively. The adoption of FIN No. 48 did not have a significant effect on our reported financial position or earnings. See Note 4.

Other Assets

Other assets primarily include deferred debt costs that are amortized to interest expense over the term of the related debt (Note 3) and the long-term portion of gas balancing receivable (see *Revenue Recognition and Gas Balancing* below). Other assets are presented net of accumulated amortization of $22 million at December 31, 2007 and $16 million at December 31, 2006.

In accordance with Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*, we determined that a portion of the purchase price of the Antero Resources Corporation acquisition (Note 13) was allocable to gas gathering contracts and goodwill. Gas gathering contracts are associated with the pipeline acquired, and the value of $140 million was determined based on the estimated discounted cash flows from those contracts. The gas gathering contracts are amortized, as a component of depreciation, depletion and amortization expense, on a unit-of-production basis using the estimated proved reserves of the related Barnett Shale properties. Accumulated amortization of acquired gas gathering contracts was $28 million as of December 31, 2007 and $19 million as of December 31, 2006. Amortization expense is expected to be approximately $7 million to $9 million annually from 2008 through 2012, depending on Barnett Shale production.

Goodwill of $215 million represents the excess of the purchase price paid for Antero Resources over the fair value of the assets acquired and liabilities assumed. In accordance with SFAS No. 142, goodwill is not amortized, but instead is subject to an annual assessment of impairment based on a fair value test performed in the fourth quarter.

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. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, requires that all derivatives be recorded on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The fair value of call options and collars are generally determined under the Black-Scholes option-pricing model. Most values are confirmed by counterparties to the derivative.

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

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

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

To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as oil or gas revenue or interest expense when the underlying transaction occurs. If it is determined that the designated hedge transaction is not probable to occur, any unrealized gains or losses are recognized immediately in the income statement as a derivative fair value gain or loss. During 2007, 2006 and 2005, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of our derivatives.

Physical delivery contracts that are not expected to be net cash settled are deemed to be normal sales. 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.

Revenue Recognition and Gas Balancing

Oil, gas and natural gas liquids revenues are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectibility of the revenue is reasonably assured. At times we may sell more or less than our entitled share of gas production. When this happens, we use the entitlement method of accounting for gas sales, based on our net revenue interest in production. Accordingly, revenue is deferred for gas deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. Our net gas imbalance receivable of $1 million at December 31, 2007, was reported in the balance sheet as a $1 million net current receivable. At December 31, 2006, our net gas imbalance payable of $2 million was reported in the balance sheet as a $3 million net current receivable and a $5 million net long-term payable.

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 $517 million in 2007, $333 million for 2006 and $185 million for 2005. These amounts are net of intercompany eliminations.

Other Revenues

Other revenues result from and are related to our ongoing major operations. These revenues include various gains and losses, including from lawsuits and other disputes, as well as from non-significant sales of property and equipment.

determines that it is probable that an asset has been impaired or a liability has been incurred, we accrue our best estimate of the loss if it can be reasonably estimated. Our legal costs related to litigation are expensed as incurred. See Note 6.

Interest

Interest expense includes amortization of deferred debt costs and is presented net of interest income of $17 million in 2007, $3 million in 2006 and $1 million in 2005, and net of capitalized interest of $30 million in 2007, $18 million in 2006 and $6 million in 2005. Interest is capitalized as proved property cost based on the weighted average interest rate and the cost of wells in process of drilling. Included in accounts payable and accrued liabilities is accrued interest of $112 million at December 31, 2007 and $54 million at December 31, 2006.

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123 (Revised 2004), *Share-Based Payment,* which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements based on their estimated grant-date fair value. We have previously recorded stock compensation pursuant to the intrinsic value method under APB Opinion No. 25, whereby compensation was recorded related to performance share and unrestricted share awards and no compensation was recognized for most stock option awards. We are using the modified prospective application method of adopting SFAS No. 123R, whereby the estimated fair value of unvested stock awards granted prior to January 1, 2006 will be recognized as compensation expense in periods subsequent to December 31, 2005, based on the same valuation method used in our prior pro forma disclosures. We have estimated expected forfeitures, as required by SFAS No. 123R, and we are recognizing compensation expense only for those awards expected to vest. Compensation expense is amortized over the estimated service period, which is the shorter of the award's time vesting period or the derived service period as implied by any accelerated vesting provisions when the common stock price reaches specified levels. All compensation must be recognized by the time the award vests. The cumulative effect of initially adopting SFAS No. 123R was immaterial. See Note 12.

The following are pro forma net income and earnings per share for the year ended December 31, 2005, 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 millions, except per share data)	Year Ended December 31, 2005
Net income as reported	$ 1,152
Add stock-based compensation expense included in the income statement, net of related tax effects	22
Deduct stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(73)
Pro forma net income	$ 1,101
Earnings per common share:	
Basic — as reported	$ 2.57
Basic — pro forma	$ 2.46
Diluted — as reported	$ 2.52
Diluted — pro forma	$ 2.41

Earnings per Common Share

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

Segment Reporting

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

Our production is sold to various purchasers, based on their credit rating and location of our production. For the year ended December 31, 2007, sales to each of two purchasers were approximately 18% and 11% of total revenues. For the year ended December 31, 2006, sales to each of two purchasers were approximately 22% and 15% of total revenues. For the year ended December 31, 2005, sales to

New Accounting Pronouncements

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, was issued. SFAS No. 157 provides guidance for using fair value to measure assets and liabilities. It applies whenever other standards require or permit assets or liabilities to be measured at fair value but it does not expand the use of fair value in any new circumstances. In November 2007, the effective date was deferred for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value on a recurring basis. The provisions of SFAS No. 157 that were not deferred are effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of SFAS No. 157, effective January 1, 2008, did not have a significant effect on our reported financial position or earnings.

In February 2007, SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115*, was issued. SFAS No. 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of SFAS No. 159, effective January 1, 2008, did not have a significant effect on our reported financial position or earnings.

In December 2007, SFAS No. 141R, *Business Combinations*, was issued. Under SFAS No. 141R, a company is required to recognize the assets acquired, liabilities assumed, contractual contingencies, and any contingent consideration measured at their fair value at the acquisition date. It further requires that research and development assets acquired in a business combination that have no alternative future use to be measured at their acquisition-date fair value and then immediately charged to expense, and that acquisition-related costs are to be recognized separately from the acquisition and expensed as incurred. Among other changes, this statement also requires that "negative goodwill" be recognized in earnings as a gain attributable to the acquisition, and any deferred tax benefits resultant in a business combination are recognized in income from continuing operations in the period of the combination. SFAS No. 141R is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning after December 15, 2008. The effect of adopting SFAS No. 141R has not been determined, but it is not expected to have a significant effect on our reported financial position or earnings.

In December 2007, SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51*, was issued. SFAS No. 160 amends ARB 51 to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. Among other requirements, this statement requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS No. 160 is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2008. The effect of adopting SFAS No. 160 is not expected to have an effect on our reported financial position or earnings.

2. RELATED PARTY TRANSACTIONS

A firm, affiliated with one of our nonemployee directors, has performed property acquisition advisory services for the Company. In February 2005, this firm was acquired by another company which continues to perform property acquisition advisory services for us, and a division of the company also performed co-manager services on our June 2007 common stock offering (Note 9) and our July and August 2007, March 2006 and April 2005 senior note offerings (see Note 3). We paid this firm total fees of $3.4 million in 2007, $78,500 in 2006 and $5.0 million in 2005, and there were no amounts payable at December 31, 2007 or 2006. In February 2008, this firm served as one of 24 co-managers on our common stock offering.

In February 2007, in recognition of the Chairman and Chief Executive Officer of the Company and as part of a charitable giving program to support higher education, the Board of Directors approved a conditional contribution of $6.8 million to assist in building an athletics and academic center at Baylor University. This contribution is to be paid in two equal installments of $3.4 million. The first payment was made May 2007 and the second is expected to be paid in the first half of 2008. Since this is a conditional contribution, the first payment is included as general and administrative expense in 2007. However, the second payment will not be made and included in general and administrative expense until the condition is satisfied. Concurrently, our Chairman and Chief Executive Officer made a $3.2 million pledge for the same project. In return for these contributions, the Company and our Chairman and Chief Executive Officer obtained naming rights for the building and certain facilities within the building.

area of $15 per foot.

3. DEBT

Our long-term debt consists of the following:

(in millions)	December 31 2007	2006
Bank debt:		
Commercial paper, 5.38% at December 31, 2007 and 5.45% at December 31, 2006	$ 772	$ 159
Revolving credit agreement due April 2012	–	–
Term loan due April 2012, 5.72% at December 31, 2007 and 6.06% at December 31, 2006	300	300
Senior notes:		
7.50%, due April 15, 2012	350	350
5.90%, due August 1, 2012, plus premium	553	–
6.25%, due April 15, 2013	400	400
4.90%, due February 1, 2014, net of discount	497	497
5.00%, due January 31, 2015, net of discount	350	350
5.30%, due June 30, 2015, net of discount	399	399
5.65%, due April 1, 2016, net of discount	400	400
6.25%, due August 1, 2017, plus premium	753	–
6.10%, due April 1, 2036, net of discount	596	596
6.75%, due August 1, 2037, plus premium	950	–
Total long-term debt	$ 6,320	$ 3,451

Because we had both the intent and ability to refinance the commercial paper balance outstanding with borrowings under our revolving credit facility due in April 2012, we have classified these borrowings as long-term debt in our consolidated balance sheets. Before the stated maturities of April 2012, we may renegotiate the revolving credit agreement and term loan to increase the borrowing commitment and/or extend the maturity.

Commercial Paper

In February 2008, we increased our commercial paper program availability to $2.5 billion. Borrowings under the commercial paper program reduce our available capacity under the revolving credit facility on a dollar-for-dollar basis. The commercial paper borrowings may have terms up to 397 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. On December 31, 2007, borrowings were $772 million at a weighted average interest rate of 5.38%. The weighted average interest rate on commercial paper borrowings was 5.42% during 2007.

Bank Debt

On December 31, 2007, we had no borrowings under our revolving credit agreement with commercial banks, and we had available borrowing capacity of $1.2 billion net of our commercial paper borrowings. In February 2008, we amended this agreement to, among other things, increase the borrowing capability to $2.5 billion and to extend the maturity date to April 1, 2013. We have annual options to request successive one-year extensions and the option to increase the commitment up to an additional $1.0 billion. The interest rate on any borrowing is generally based on the one-month LIBOR plus 0.40%. 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 is 0.09%. The agreement requires us to maintain a debt-to-total capitalization ratio of not more than 65%. We use the facility for general corporate purposes and as a backup facility for our commercial paper program. We did not make any borrowings under our revolving credit facility during 2007.

In February 2008, we also amended our $300 million term loan credit agreement to increase outstanding borrowings to $500 million and to extend the maturity date to April 1, 2013. In March 2007, we amended our $300 million term loan credit agreement to conform its covenants and pricing to our bank revolving credit agreement and to extend the maturity.

Additionally in February 2008, we entered into a new five-year unsecured term loan agreement with The Royal Bank of Scotland Finance (Ireland) that provides for a maximum loan amount of $100 million available in a single advance that matures February 5, 2013. The interest rate is currently based on LIBOR plus 0.34%, and interest is paid at least quarterly. Other terms and conditions are substantially the same as our term loan. The proceeds were used for general corporate purposes.

Senior Notes

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

In September 2004, we sold $350 million of 5% senior notes that were issued at 99.918% of par to yield 5.011% to maturity. The notes are due in January 2015 and interest is payable each January 31 and July 31. Net proceeds of $347 million were used to reduce bank debt associated with our 2004 acquisitions.

In April 2005, we sold $400 million of 5.3% senior notes at 99.683% of par to yield 5.338% to maturity. The notes mature in June 2015 and interest is payable each June 30 and December 30. Net proceeds of approximately $395 million were used to reduce borrowings under our bank revolving credit facility.

In March 2006, we sold $400 million of 5.65% senior notes due April 1, 2016 and $600 million of 6.1% senior notes due April 1, 2036. The 5.65% senior notes were issued at 99.917% of par to yield 5.661% to maturity. The 6.1% senior notes were issued at 99.346% of par to yield 6.148% to maturity. Interest is payable on both series of notes each April 1 and October 1, beginning October 1, 2006. Net proceeds of approximately $987 million were used to reduce borrowings outstanding under our bank revolving credit facility and for other general corporate purposes.

In July 2007, we sold $300 million of 5.9% senior notes due August 1, 2012, $450 million of 6.25% senior notes due August 1, 2017 and $500 million of 6.75% senior notes due August 1, 2037. In August 2007, we sold an additional $250 million of the 5.9% senior notes, $300 million of the 6.25% senior notes and $450 million of the 6.75% senior notes that constituted a further issuance of the senior notes issued in July 2007. Together, the 5.9% senior notes were issued at 100.585% of par to yield 5.761% to maturity. The 6.25% senior notes were issued at 100.419% of par to yield 6.193% to maturity. The 6.75% senior notes were issued at 100.022% of par to yield 6.748% to maturity. Interest is payable on each series of notes on February 1 and August 1 of each year, beginning February 1, 2008. Net proceeds of $2.24 billion were used to fund a portion of the acquisition of properties from Dominion Resources, Inc. (Note 13) and to pay down outstanding commercial paper borrowings.

The senior notes require no sinking fund. We may redeem all or a part of the senior notes at any time at a price of 100% of their principal balance plus accrued interest and a make-whole premium payment. The make-whole premium is calculated as any excess over the principal balance of the present value of remaining principal and interest payments at the U.S. Treasury rate for a comparable maturity plus no more than 0.25%.

4. INCOME TAX

The following reconciles our income tax expense to the amount calculated at the statutory federal income tax rate:

(in millions)	2007	2006	2005
Income tax expense at the federal statutory rate (35%)	$ 925	$ 1,036	$ 634
State and local income taxes and other (a)	26	65	24
Income tax expense	$ 951	$ 1,101	$ 658

(a) The 2006 provision includes $34 million related to enactment of a new State of Texas margin tax.

Components of income tax expense are as follows:

(in millions)	2007	2006	2005
Current income tax (a)	$ 292	$ 572	$ 243
Deferred income tax	659	505	398
Net operating loss carryforwards used	–	24	17
Income tax expense	$ 951	$ 1,101	$ 658

(a) The current income tax provision exceeds cash tax expense by the benefit realized upon exercise of stock options or vesting of stock awards in excess of amounts expensed in the financial statements. This benefit, which is recorded in additional paid-in capital, was $64 million in 2007, $50 million in 2006 and $21 million in 2005.

liability of $2.6 billion at December 31, 2007 and as a current liability of $263 million and a long-term liability of $2.0 billion at December 31, 2006. Significant components of net deferred tax assets and liabilities are:

(in millions)	December 31 2007	2006
Deferred tax assets:		
Derivative fair value loss	$ 91	$ 22
Other	68	43
Total deferred tax assets	159	65
Deferred tax liabilities:		
Property and equipment	(2,649)	(1,971)
Derivative fair value gain	(73)	(319)
Other	(27)	(16)
Total deferred tax liabilities	(2,749)	(2,306)
Net deferred tax liabilities	$ (2,590)	$ (2,241)

At the time of adoption of FIN 48 and as of December 31, 2007, we did not have any unrecognized tax benefits. As a result, the only differences between our financial statements and our income tax returns relate to normal timing differences such as depreciation, depletion and amortization, which are recorded as deferred taxes on our consolidated balance sheets.

In second quarter 2007, the Internal Revenue Service completed its examination of our federal income tax returns for 2003 and 2004. Additional federal tax resulting from this examination was fully accrued in our December 31, 2006 consolidated financial statements as current income tax payable. Under the terms of the final settlement with the IRS, we incurred immaterial interest expense and no penalties. Subsequent amendment of our state tax returns for these years did not have a significant effect on our results of operations or financial position. Tax years 2003 and 2004 remain subject to examination by state jurisdictions, and subsequent years are open to both federal and state examination.

5. ASSET RETIREMENT OBLIGATION

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The following is a summary of asset retirement obligation activity for the years ended December 31, 2007 and 2006:

(in millions)	2007	2006
Asset retirement obligation, January 1	$ 307	$ 223
Revisions in the estimated cash flows	39	36
Liability incurred upon acquiring and drilling wells	87	35
Liability settled upon plugging and abandoning wells	(2)	(3)
Accretion of discount expense	22	16
Asset retirement obligation, December 31	453	307
Less current portion	(3)	(4)
Asset retirement obligation, long term	$ 450	$ 303

6. COMMITMENTS AND CONTINGENCIES

Leases

We lease compressors, offices, vehicles, aircraft and certain other equipment in our primary locations under noncancelable operating leases. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2007, minimum future lease payments for all noncancelable lease agreements were as follows:

(in millions)	
2008	$ 24
2009	21
2010	19
2011	13
2012	7
Remaining	8
Total	$ 92

Amounts incurred under operating leases (including renewable monthly leases) were $57 million in 2007, $55 million in 2006 and $41 million in 2005.

These future commitments will result in expected payments of $147 million in 2008 and $26 million in 2009.

Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under our firm transportation contracts, therefore avoiding payment for deficiencies. As of December 31, 2007, maximum commitments under our transportation contracts were as follows:

(in millions)	
2008	$117
2009	122
2010	121
2011	116
2012	107
Remaining	416
Total	$999

In December 2006, we entered into a ten-year firm transportation contract that commences upon completion of a new 502-mile pipeline spanning from southeast Oklahoma to east Alabama. Upon the pipeline's completion, currently expected in first quarter 2009, we will transport gas volumes for a minimum transportation fee of $2 million per month plus fuel not to exceed 1.2% of the sales price, depending on receipt point and other conditions. The potential effect of this agreement is not included in the above summary of our transportation contract commitments since our commitment is contingent upon completion of the pipeline.

Guarantees

Under the terms of some of our operating leases for compressors, airplanes and vehicles, we have various residual value guarantees and other payment provisions upon our election to return the equipment under certain specified conditions. As of December 31, 2007, we estimate the total contingent payable under these guarantees does not exceed $5 million.

Employment Agreements

Three executive officers entered into year-to-year employment agreements with us in May 2006. The agreements are automatically renewed each December 1 unless terminated by either party upon thirty days notice prior to each November 30. Under these agreements, the officers receive a minimum annual salary of $1,200,000, $675,000 and $540,000, 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 (i) the officer terminates his employment for good reason, as defined in the agreement, (ii) we terminate the employee without cause, (iii) the officer dies or becomes disabled, or (iv) 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.

On December 31, 2007, the Chairman and Chief Executive Officer's employment agreement was amended relating to payments to be received by the Chairman and Chief Executive Officer upon a change of control. The amendment eliminates the requirement that the Company provide a gross-up payment in connection with any excise tax and to provide that the total aggregate payments to be made under the employment agreement and any other agreement providing payments upon a change in control be reduced to the maximum amount that can be paid without the imposition of the excise tax.

Upon retirement, each of these officers will enter into an eighteen-month consulting agreement under which the officer will receive a monthly payment based on his annual salary at the time of retirement, plus $10,000 a month for expenses. The officer will also become fully vested in any outstanding share-based awards unless otherwise provided in the award agreement.

Commodity Commitments

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

and minimum future commitments of $142 million in 2008, $61 million in 2009 and $15 million in 2010. Early termination of these contracts at December 31, 2007 would have required us to pay maximum penalties of $129 million. We do not expect to pay any early termination penalties related to these contracts.

Litigation

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the U.S. District Court for the Western District of Oklahoma by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the U.S. False Claims Act against the Company and certain of our subsidiaries. The plaintiff alleges that we underpaid royalties on natural gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% as a result of mismeasuring the volume of natural gas, incorrectly analyzing its heating content and improperly valuing the natural gas during at least the past ten years. The plaintiff seeks treble damages for the unpaid royalties (with interest, attorney fees and expenses), civil penalties between $5,000 and $10,000 for each violation of the U.S. False Claims Act, and an order for us to cease the allegedly improper measuring practices. This lawsuit against us and similar lawsuits filed by Grynberg against more than 300 other companies were consolidated in the United States District Court for Wyoming. In October 2002, the court granted a motion to dismiss Grynberg's royalty valuation claims, and Grynberg's appeal of this decision was dismissed for lack of appellate jurisdiction in May 2003. In response to a motion to dismiss filed by us and other defendants, in October 2006 the district judge held that Grynberg failed to establish jurisdictional requirements to maintain the action against us and other defendants and dismissed the action for lack of subject matter jurisdiction. In September 2007, the district judge dismissed those claims against us pertaining to the royalty value of carbon dioxide. Grynberg has filed appeals of these decisions. While we are unable to predict the final outcome of this case, 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 July 2005 a predecessor company, Antero Resources Corporation, was served with a lawsuit styled *Threshold Development Company, et al. v. Antero Resources Corp.*, which lawsuit was filed in the District Court of Wise County, Texas. The plaintiffs are surface owners, royalty owners and prior working interest owners in several oil and gas leases as well as other contractual agreements under which Antero Resources Corporation owned an interest. Antero Resources Corporation, the defendant, was acquired by us on April 1, 2005. The claims relate to alleged events pre-dating the acquisition and concern non-payment of royalties, improper calculation of royalties, improper pricing related to royalties, trespass, failure to develop and breach of contract. We have settled all claims related to the payment of royalties and trespass. Under the remaining claims, the plaintiffs are seeking both damages and termination of the existing oil and gas leases covering their interests. The court has ordered the parties to mediation, which has not been scheduled. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Based on a review of the current facts and circumstances with counsel, management has provided for what is believed to be a reasonable estimate of the loss exposure for this matter. While acknowledging the uncertainties of litigation, management believes that the ultimate outcome of this matter will not have a material effect on our earnings, cash flows or financial position.

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

In May 2005, in recognition of the Chairman and Chief Executive Officer of the Company, in support of local education and to benefit our ongoing oil and gas business endeavors in this area, the Board of Directors approved a pledge to contribute $3.1 million to a school in Fort Worth. Of this amount, $3 million is to be used for capital improvements. The remaining $100,000 is to be used for a scholarship fund for economically disadvantaged students. This pledge is to be paid annually in four equal installments of $775,000, the first of which was paid in June 2005 with the remaining payments due in June of each subsequent year. The total contribution was expensed as general and administrative expense in 2005. As of December 31, 2007, the remaining $0.8 million pledge payable is included in accounts payable and accrued liabilities.

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.

To secure tubular goods required to support our drilling program, we provide a forecast to a tubular goods supplier who commits to deliver, at market prices, our next quarter's tubular products. There is no minimum order requirement, and the forecast can be adjusted 60 to 90 days prior to shipment.

expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

In addition to drilling four wells to earn our 50% working interest in the 69,500 acres granted under our Piceance Basin farm-in agreement with ExxonMobil Corporation, which we completed in 2007 (Note 13), we are required to continue to drill wells periodically to retain the undeveloped leasehold until the entire acreage position has been drilled.

See Note 2.

7. FINANCIAL INSTRUMENTS

We use commodity-based and financial 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. We also may 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. Therefore, these contracts are not recorded in the financial statements.

All derivatives are recorded on the balance sheet at estimated fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or the value confirmed by the counterparty. Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income (loss), which is later transferred to earnings when the hedged transaction occurs. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of the hedge derivatives, are recorded in derivative fair value (gain) loss in the income statement.

Btu Swap Contracts

In 1995, we entered a contract to sell gas based on crude oil pricing, also referred to as the Enron Btu swap contract. This contract was terminated as a result of the Enron bankruptcy in December 2001. Because the contract pricing was not clearly and closely associated with natural gas prices, it was considered a non-hedge derivative financial instrument, 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 August 2005 through July 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 were recorded as a derivative (gain) loss in the income statement.

Btu swap contracts outstanding at December 31, 2005 had a net fair value loss of $23 million. As of February 28, 2006, we terminated the remaining portion of these contracts, resulting in total payments to the counterparty of $7 million in first quarter 2006.

Commodity Price Hedging Instruments

We periodically enter into futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on natural gas, crude oil and natural gas liquids 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. See Note 8.

Derivative Fair Value (Gain) Loss

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

(in millions)	2007	2006	2005
Change in fair value of Btu swap contracts	$ –	$ (16)	$ 23
Change in fair value of other derivatives that do not qualify for hedge accounting	–	(19)	(37)
Ineffective portion of derivatives qualifying for hedge accounting	(11)	(67)	1
Derivative fair value (gain) loss	$ (11)	$ (102)	$ (13)

The gains in 2006 and 2005 related to derivatives that do not qualify for hedge accounting are primarily related to natural gas basis swap agreements. Except to the extent basis swap agreements are utilized in conjunction with NYMEX future contracts, they cannot qualify for hedge accounting.

(in millions)	2007	2006	2005
Net cash (received from) paid to counterparties	$ (54)	$ (63)	$ 26
Non-cash change in derivative fair value	43	(39)	(39)
Derivative fair value (gain) loss	$ (11)	$ (102)	$ (13)

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, 2007 and 2006. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2007		December 31, 2006	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivative Assets:				
Fixed-price natural gas futures and basis swaps	$ 198	$ 198	$ 669	$ 669
Fixed-price crude oil futures and differential swaps	1	1	191	191
Derivative Liabilities:				
Fixed-price natural gas futures and basis swaps	(13)	(13)	(37)	(37)
Fixed-price crude oil futures and differential swaps	(208)	(208)	(1)	(1)
Fixed-price natural gas liquids futures	(22)	(22)	–	–
Net derivative (liability) asset	$ (44)	$ (44)	$ 822	$ 822
Long-term debt	$ (6,320)	$ (6,438)	$ (3,451)	$ (3,427)

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

Changes in fair value of derivative assets and liabilities are the result of changes in natural gas, crude oil and natural gas liquids prices. 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 (loss) until the hedged transaction occurs.

Concentrations of Credit Risk

Although our cash equivalents, accounts receivable and derivative assets 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. We currently have the majority of our credit exposure with several A- or better rated integrated energy companies. Financial and commodity-based swap contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions, and we have master netting agreements with counterparties that provide for offsetting payables against receivables from separate derivative contracts. Letters of credit or other appropriate security are obtained as considered necessary to limit risk of loss. Our allowance for collectibility of all accounts receivable was $7 million at December 31, 2007 and $5 million at December 31, 2006.

8. COMMODITY SALES COMMITMENTS

Our policy is to consider hedging 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 may enter into hedging agreements because of the benefits of predictable, stable cash flows.

In addition to selling gas under fixed price physical delivery contracts, we enter futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on natural gas, crude oil and natural gas liquids sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the 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, crude oil and natural gas liquids sales through December 2008.

shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 7 regarding accounting for commodity hedges.

Production Period		Mcf per Day	Average NYMEX Price per Mcf
2008	January to March	1,100,000	$ 8.33
	April to December	1,200,000	$ 8.32

The price we receive for our gas production is generally less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors. We have entered sell basis swap agreements that effectively fix the basis adjustment as shown below. Not all of our sell basis swap agreements are designated as hedges for hedge accounting purposes.

Production Period		Mcf per Day	Weighted Average Sell Basis per Mcf (a)
2008	January (b)	610,000	$ 0.43
	February (b)	680,000	$ 0.42
	March (b)	560,000	$ 0.41
	April to June (b)	360,000	$ 0.57
	July to October (b)	330,000	$ 0.60
	November to December (b)	220,000	$ 0.78
2009	January to March (b)	160,000	$ 0.97
	April to December (b)	150,000	$ 1.02
2010	January to December	50,000	$ 0.27

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

(b) 2008 and 2009 amounts include 100,000 Mcf per day at $1.39 to be delivered in the Rocky Mountain Region.

Net settlements on futures and sell basis swap hedge contracts increased gas revenues by $658 million in 2007 and $618 million in 2006 and decreased gas revenue by $127 million in 2005. As of December 31, 2007, an unrealized pre-tax derivative fair value gain of $177 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). This fair value gain is expected to be reclassified into earnings in 2008. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date. The settlement of futures contracts and sell basis swap agreements related to January 2008 gas production increased gas revenue by approximately $33 million, or $0.63 per Mcf.

Crude Oil

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

Production Period		Bbls per Day	Average NYMEX Price per Bbl
2008	January to December	30,000	$ 74.20

We have entered crude sweet and sour differential swaps of $4.00 per Bbl for 10,000 Bbls per day of sour crude oil production for January to December 2008.

Net gains on futures and differential swap hedge contracts increased oil revenue by $24 million in 2007 and $3 million in 2006, and net losses reduced oil revenue by $75 million in 2005. As of December 31, 2007, an unrealized pre-tax derivative fair value loss of $207 million related to cash flow hedges of oil price risk was recorded in accumulated other comprehensive income (loss). This fair value loss is expected to be reclassified into earnings in 2008. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date. The settlement of futures contracts, swap agreements and differential swap contracts related to January 2008 production decreased oil revenue by approximately $17 million, or $10.97 per Bbl.

Natural Gas Liquids

We have entered into natural gas liquids futures contracts 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.

Production Period		Bbls per Day	Average Price per Bbl
2008	January to December	5,000	$ 44.22

in 2008. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date. The settlement of futures contracts related to January 2008 production decreased natural gas liquids revenue by approximately $3 million, or $5.52 per Bbl.

Transportation Contracts

In connection with our commitments under our transportation contracts (Note 6), we have entered purchase basis swap agreements related to potential purchase of gas volumes to be transported. Purchase basis swap agreements are not designated as hedges for hedge accounting purposes.

Period		Mcf per Day	Weighted Average Purchase Basis per Mcf (a)
2008	January to March	125,000	$ 0.69
	April to October	50,000	$ 0.83
	November to December	40,000	$ 0.88
2009	January to March	40,000	$ 0.88

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

Physical Delivery Contracts

In 1998, we sold a production payment, payable from future production from certain properties acquired in an acquisition, to EEX Corporation for $30 million. The acquisition was recorded net of the sale of the production payment. Under the terms of the production payment conveyance and related delivery agreement, we committed to deliver to EEX a total of approximately 34 Bcf 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 Bcf (15 Bcf net) of gas under the production payment for $21 million. We began delivery of the remaining 16 Bcf of gas in September 2006. As of December 31, 2007, remaining volumes to be delivered under this commitment are 12 Bcf.

As part of the July 2007 Dominion acquisition, Dominion retained interests in certain of the acquired properties. Under the terms of the acquisition and the retained interest agreements, Dominion retained the rights to approximately 13 Bcf of gas beginning from the date of the acquisition through February 2009. As of December 31, 2007 remaining volumes to be delivered to Dominion are 7 Bcf.

9. EQUITY

Stock Splits

We effected a five-for-four stock split on December 13, 2007 and a four-for-three stock split on March 15, 2005. 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)	2007	2006	2005	2007	2006	2005
Balance, January 1	464,342	456,526	435,536	4,900	2,069	1,563
Issuance/vesting and forfeiture of performance, restricted and unrestricted shares	1,413	1,521	540	240	81	506
Stock option and warrant exercises	3,117	3,101	3,783	–	–	–
Treasury stock purchases	–	–	–	–	2,750	–
Common stock offering	21,562	–	–	–	–	–
Issuance for acquisition of corporation	–	3,194	16,667	–	–	–
Balance, December 31	490,434	464,342	456,526	5,140	4,900	2,069

In February 2008, we completed a public offering of 23 million common shares at $55.00 per share. After underwriting discount and other offering costs of $42 million, net proceeds of $1.2 billion were used to fund a portion of the $1.0 billion of property acquisitions expected to close in first quarter 2008 and to repay indebtedness under our commercial paper program. (Note 13).

In June 2007, we completed a public offering of 21.6 million common shares at $48.40 per share. After underwriting discount and other offering costs of $35 million, net proceeds of $1.0 billion were used to fund a portion of the acquisition of natural gas and oil properties from Dominion Resources, Inc. (Note 13).

Our acquisition of Antero Resources Corporation in April 2005 was partially funded through issuance to the seller of 16.7 million shares of common stock (Note 13). We filed a shelf registration with the Securities and Exchange Commission for the resale of the common stock including shares to be issued upon exercise of warrants. See *Common Stock Warrants* below.

Treasury Stock

In August 2004, our Board of Directors authorized the repurchase of up to 25 million shares of our common stock which may be purchased from time to time in open market or negotiated transactions. In June 2006, we repurchased 2.8 million shares of our common stock on the open market at $30.24 per share, or a total of $83 million. As of December 31, 2007, we have repurchased 2.8 million shares.

Stockholder Rights Plan

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

Shelf Registration Statement

In June 2006, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities or common stock. The securities will be offered 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.

Common Stock Warrants

Our purchase of Antero Resources Corporation was partially funded by issuance of warrants to purchase 2.6 million shares of common stock at $20.78 per share (Note 13). The warrants expire in April 1, 2010.

Common Stock Dividends

The Board of Directors declared quarterly dividends of $0.04 per common share for the first three quarters of 2005, $0.06 per common share for fourth quarter 2005 and the first three quarters of 2006, $0.072 per common share for fourth quarter 2006 and $0.096 per common share for the first three quarters of 2007. In November 2007, the Board of Directors declared a five-for-four stock split of its common stock and increased its quarterly dividend to $0.12 per common share for the fourth quarter 2007, effecting a 25% dividend increase. On February 19, 2008, the Board of Directors declared a first quarter 2008 dividend of $0.12 per common share.

In January 2006, the Board of Directors declared a dividend to common stockholders, consisting of all 21.7 million Hugoton Royalty Trust units owned by us. The dividend ratio of 0.047688 trust units for each common share outstanding was set on the record date of April 26, 2006. The units were distributed on May 12, 2006, when this dividend was recorded. We recorded this dividend at $614 million, or approximately $1.35 per common share, the fair market value of the units based on the May 12, 2006 average high and low New York Stock Exchange trade price of $28.31.

The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Board of Directors and will depend on our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters the Board of Directors deems relevant.

See Note 12.

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

(in millions, except per share data)	Earnings	Shares	Earnings per Share
2007			
Basic	$ 1,691	471.9	$ 3.58
Effect of dilutive securities:			
Stock options	–	5.7	
Warrants	–	1.4	
Diluted	$ 1,691	479.0	$ 3.53
2006			
Basic	$ 1,860	456.1	$ 4.08
Effect of dilutive securities:			
Stock options	–	5.1	
Warrants	–	1.0	
Diluted	$ 1,860	462.2	$ 4.02
2005			
Basic	$ 1,152	448.1	$ 2.57
Effect of dilutive securities:			
Stock options	–	8.5	
Warrants	–	0.4	
Diluted	$ 1,152	457.0	$ 2.52

11. SUPPLEMENTAL CASH FLOW INFORMATION

The consolidated statements of cash flows exclude the following non-cash transactions:

- Distribution of 21.7 million Hugoton Royalty Trust units as a dividend to common stockholders in May 2006 (Note 9)
- Non-cash components of the June 2006 Peak Energy Resources acquisition purchase price, including issuance of 3.2 million shares of common stock and assumption of other liabilities (Note 13)
- Exchange of producing properties with ConocoPhillips in March 2005 and Occidental Petroleum in September 2005 (Note 13)
- Non-cash components of the April 2005 Antero Resources acquisition purchase price, including issuance of 16.7 million shares of common stock and warrants to purchase 2.6 million shares of common stock, and assumption of debt and other liabilities (Note 13)
- The following restricted share activity (Note 12):
  - Grants of 1.4 million shares in 2007 and 1.3 million shares in 2006
  - Vesting of 427,000 shares in 2007
  - Forfeitures of 48,000 shares in 2007
- Grants and immediate vesting of unrestricted common shares to nonemployee directors totaling 25,000 shares in each of 2007 and 2006 and 23,000 shares in 2005 (Note 12)
- The following performance share activity (Note 12):
  - Grants of 187,000 shares in 2006 and 518,000 shares in 2005
  - Vesting of 166,000 shares in 2007, 201,000 shares in 2006 and 1.3 million shares in 2005
  - Forfeitures of 15,000 shares in 2007

Interest payments totaled $231 million (including $30 million of capitalized interest) in 2007, $172 million (including $18 million of capitalized interest) in 2006 and $150 million (including $6 million of capitalized interest) in 2005. Net income tax payments were $284 million in 2007, $556 million in 2006 and $248 million in 2005.

Prior to January 1, 2006, we did not recognize compensation expense related to stock options granted and, therefore, the tax benefit realized upon exercise of these stock options has been recorded as an increase in additional paid-in capital. This tax benefit decreased our current income tax payable and, as reflected in our consolidated statements of cash flows, increased our cash provided by operating activities by $21 million in 2005. Upon adoption of SFAS 123R (Note 12), this tax benefit of $57 million for 2007 and $50 million for 2006 has been classified as cash provided by financing activities.

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 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 $14 million in 2007, $11 million in 2006 and $9 million in 2005.

Post-Retirement Health Plan

Effective January 1, 2001, we adopted a medical plan for employees who retire at age 55 or over, as well as directors age 55 or over, with a minimum of five years service. During 2003, our retiree medical plan was amended to provide benefits to employees and directors when their combined age and qualified years of service total 60, with a minimum age of 45 and a minimum of five years of service. During 2007, our retiree medical plan was again amended to extend the minimum age to 50 and a minimum of 10 years of service for current employees. However, employees who were eligible under previous eligibility rules were grandfathered in under the previous rules. Also, directors are still eligible to receive benefits under the previous eligibility rules. Benefits under the plan are the same as for active employees, and continue until the retired employee or director or dependents are eligible for Medicare or another similar state health insurance program. Post-retirement medical benefits are not prefunded but are paid when incurred. The plan's benefit obligation, funded status and net periodic benefit cost for 2007, 2006 and 2005 were as follows:

	December 31		
(in millions)	2007	2006	2005
Benefit obligation at December 31	$ 17	$ 8	$ 7
Funded status	$ (17)	$ (8)	$ (7)
Net periodic benefit cost	$ 2	$ 1	$ 1
Accrued benefit liability, as recognized in the consolidated balance sheet at December 31	$ (17)	$ (8)	$ (5)

During December 2006, we adopted the provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — An Amendment of FASB Statements No. 87, 88, 106, and 132R,* that required us to recognize in our consolidated balance sheet a liability for the underfunded status of our postretirement health plan as of December 31, 2007 and 2006. This liability, which is equal to the amount shown in the table above, is included as part of other long-term liabilities. The unrecognized portion of the liability of $8 million, net of a deferred tax asset of $3 million as of December 31, 2007, and of $3 million, net of a deferred tax asset of $1 million as of December 31, 2006, was recorded as a reduction to accumulated other comprehensive income (loss).

Unrecognized net actuarial loss is amortized to expense over the estimated average remaining service life of plan participants and prior service cost is amortized over a remaining life of eight years. Including such amortization, the 2008 accrued benefit cost is expected to be approximately $3 million.

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

	2007	2006	2005
Weighted average discount rate	6%	6%	6%
Health care cost trend rate assumed for the following year	8.5%	9%	8.5%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	6%	6%	6%
Year that the rate reaches the ultimate trend rate	2013	2013	2010

Assumed health care cost trends have a significant effect on the amounts reported for health care plans. A one percentage point change in assumed health care cost trend rates would have a $2 million or less effect on both total service and interest cost and the post-retirement benefit obligation as of December 31, 2007.

Through 2017, projected benefit payments, which reflect expected future service, are not expected to exceed $2 million in any one year and are less than $10 million in total.

Stock Incentive Plans

In November 2004, stockholders approved the 2004 Stock Incentive Plan under which 30 million shares of common stock were available for grants of stock awards. In May 2006, stockholders approved certain amendments to the 2004 Plan including increasing the shares available for grants of stock awards to 42.2 million shares. Prior to approval of the 2004 Plan, grants of stock awards were made pursuant to the 1998 Stock Incentive Plan. No further grants will be made under the 1998 Plan. Stock award grants are subject to certain limitations as specified in the Plan. The maximum term of stock awards is ten years under the 1998 Plan and seven years under the 2004 Plan. As a result of the May 12, 2006 distribution of the Hugoton Royalty Trust units (Note 9), appropriate antidilution adjustments were made to stock awards outstanding on that date.

each year:

(in millions)	December 31 2007	2006	2005
Non-cash stock option compensation expense	$ 42	$ 53	$ –
Non-cash performance share and unrestricted share compensation expense	4	8	34
Non-cash restricted stock compensation expense	19	2	–
Related tax benefit recorded in income statement	24	23	12
Intrinsic value of stock option exercises	170	136	60
Income tax benefit on exercise of stock options or vesting of stock awards (a)	64	50	21
Grant date fair value of stock options vested	35	24	78

(a) Recorded as additional paid-in-capital

Included in stock option compensation expense in 2006 is $36 million related to options granted during May 2006, which were subject to accelerated vesting provisions upon retirement under employment agreements. Under SFAS No. 123R, stock option awards subject to such vesting provisions granted to retirement-eligible employees are expensed upon grant rather than over the expected vesting period (Note 6). In 2005 and prior, before adoption of SFAS No. 123R, performance share compensation was recorded at the vesting price, recognized ratably over the estimated vesting period or at actual vesting, if earlier or if the vesting period could not be reasonably assessed.

Stock Options

Stock options granted under the 2004 Plan generally vest and become exercisable ratably over a three-year period, and may include a provision for accelerated vesting when the common stock price reaches specified levels as determined by the Compensation Committee of the Board of Directors. Some stock options granted in 2007 and 2006 vest only when the common stock reaches specified levels. There was a total of 23.0 million options outstanding under the 2004 and 1998 Plans at December 31, 2007, including 14.5 million that were exercisable at that date. Of the remaining options, 6.5 million vest over three years at a rate of one-third at each grant anniversary date, 1.0 million vested when the stock price closed above $56 in January 2008 and 1.0 million vest when the stock price closes at or above $60.

The following summarizes option activity and balances for the year ended December 31, 2007:

	Weighted-Average Exercise Price	Stock Options (in thousands)	Weighted-Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Balance at January 1, 2007	$ 23.73	24,782		
Grants	50.01	4,278		
Exercises	18.22	(5,864)		
Forfeitures	32.75	(196)		
Balance at December 31, 2007	$ 29.94	23,000	5.0	$ 493
Exercisable at December 31, 2007	$ 23.25	14,502	4.3	$ 408

As a result of options exercised in 2007, outstanding common stock increased by 3.1 million shares and stockholders' equity increased by $38 million.

Performance Shares

Performance shares granted under the 2004 Plan are subject to restrictions determined by the Compensation Committee of the Board of Directors and are subject to forfeiture if performance criteria are not met. Otherwise, holders of performance shares generally have all the voting, dividend and other rights of other common stockholders. To date, the performance criteria for all awards has been the achievement of specified increases in the common stock price above the market price at the grant date. Performance share grants in 2006 were to key employees other than executive officers.

Restricted Shares

We granted 1,388,000 restricted shares in 2007 and 1,309,000 restricted shares in 2006 to key employees other than executive officers. These shares vest over three years, with one-third vesting at each grant anniversary date. Holders of restricted shares generally have all the voting, dividend and other rights of other common stockholders.

Nonemployee directors are each eligible to receive discretionary stock awards under the 2004 Plan covering up to 25,000 shares annually, as approved by the Corporate Governance and Nominating Committee and the Board of Directors. Nonemployee directors received 4,166 shares each totaling approximately 25,000 unrestricted shares in 2007 and 2006 and 4,166 shares to five directors and 2,083 to one director totaling approximately 23,000 unrestricted shares in 2005 under the 2004 Plan. In November 2005, nonemployee directors received 20,000 stock options each totaling 120,000 stock options, 50% of which vested in 2005 when the common stock price closed above the target price of $36 and 50% which vested in 2006 when the common stock price closed above the target price of $40. In November 2006, nonemployee directors received 20,000 stock options each totaling 120,000 stock options, 50% of which vested in 2007 when the stock closed above the target price of $42 and 50% which vested in 2007 when the common stock price closed above the target price of $46. In November 2007, nonemployee directors received 20,000 stock options each totaling 120,000 stock options, 50% of which vested when the common stock price closed above the target price of $56 in January 2008 and 50% of which vest when the common stock price closes at or above the target price of $60.

Nonvested Stock Awards

The following summarizes the status of the nonvested stock options, performance shares and restricted shares as of December 31, 2007 and changes for the year ended December 31, 2007:

	Stock Options		Performance Shares		Restricted Shares	
(in thousands, except per share amounts)	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares
Nonvested at January 1, 2007	$ 10.58	7,715	$ 26.81	181	$ 38.28	1,309
Vested	10.57	(3,299)	26.86	(166)	38.28	(427)
Grants	15.29	4,278	–	–	50.02	1,388
Forfeitures	10.82	(196)	26.19	(15)	39.75	(48)
Nonvested at December 31, 2007	$ 12.95	8,498	$ –	–	$ 45.58	2,222

As of December 31, 2007, the remaining unrecognized compensation expense related to nonvested stock options was $70 million. Total deferred compensation at December 31, 2007 related to restricted shares was $89 million. For these nonvested stock awards at December 31, 2007, we estimate that stock incentive compensation for service periods after December 31, 2007 will be $92 million in 2008, $46 million in 2009 and $21 million in 2010. The weighted-average remaining vesting period is 1.5 years for stock options and 2.5 years for restricted shares.

Estimated Fair Value of Grants

Prior to adoption of SFAS No. 123R, we used the Black-Scholes option-pricing model to estimate the fair value of stock options and the intrinsic value method of valuing performance shares. Beginning January 1, 2006, we began using a lattice model to value stock option grants that time vest and a Monte Carlo simulation model to value performance shares and stock options that vest, or include a provision for accelerated vesting, when the common stock price reaches specified levels.

During 2007 and 2006, we used both a trinomial lattice model and a Monte Carlo simulation model to determine the fair value of options granted, and during 2006, we used a Monte Carlo simulation model to determine the fair value of performance shares granted. For restricted stock grants, the fair value is equal to the closing price of our common stock on the grant date.

The trinomial lattice model requires inputs for risk-free interest rate, dividend yield, volatility, contract term, average vesting period, post-vest turnover rate and suboptimal exercise factor. Both expected life and fair value are outputs of this model. The Monte Carlo simulation model requires inputs for risk-free interest rate, dividend yield, volatility, contract term, target vesting price, post-vest turnover rate and suboptimal exercise factor. The suboptimal exercise factor does not affect the valuation of the performance shares since ownership is transferred at vesting. Expected life, derived vesting period and fair value are outputs of this model.

The risk-free interest rate is based on the constant maturity nominal rates of U.S. Treasury securities with remaining lives throughout the contract term on the day of the grant. The dividend yield is the expected common stock annual dividend yield over the expected life of the option or performance share, expressed as a percentage of the stock price on the date of grant. The volatility factors are based on a combination of both the historical volatilities of our stock and the implied volatility of traded options on our common stock. Contract term is seven years. For options subject to time vesting, the average vesting period is two years, based on each grant vesting ratably over a three-year period. For options subject to vesting when the common stock reaches a specified price, the target vesting price is specified by the award. The post-vesting turnover rate is 4.1% and the suboptimal exercise factor is 1.7, and are both based on actual historical exercise activity. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by certain employees who receive stock option grants, and subsequent events are not indicative of the reasonableness of the original fair value estimates.

For the fair value of stock options awarded before 2006, we used the Black-Scholes option pricing model which utilizes assumptions different from those described above. The expected term was based on the historical exercise activity. The risk-free interest rate was the yield available on U.S. Treasury securities with a remaining term equal to the expected life of the option. The dividend yield was determined in the same manner as described above for the lattice model. The volatility factor was based on the historical volatility of our common stock over the expected life of the option.

During the year ended December 31, 2007, we granted 4.3 million options with an estimated total grant-date fair value of $65 million and a weighted-average fair value of $15.29. During 2006, we granted 6.8 million options with an estimated total grant-date fair value of $74 million and a weighted-average fair value of $10.89 per option. During the year ended December 31, 2005, we granted 5.2 million options with a weighted-average fair value of $8.15. Fair values were determined using the following assumptions:

	2007	2006	2005
Weighted-average expected term (years)	4.6	4.4	3.5
Range of risk-free interest rates	3.4% – 5.0%	4.3% – 5.2%	–
Weighted-average risk-free interest rates	3.8%	4.9%	4.0%
Dividend yield	0.8%	0.7%	0.7%
Range of volatility	26% – 33%	29% – 35%	–
Weighted-average volatility	32%	32%	35%

13. ACQUISITIONS

On July 31, 2007, we acquired both producing and unproved properties from Dominion Resources, Inc. for $2.5 billion, subject to typical post-closing adjustments. These properties are located in the Rocky Mountain Region, the San Juan Basin and South Texas. The acquisition was funded by the issuance of 21.6 million shares of our common stock in June 2007 for net proceeds of $1.0 billion (Note 9), the issuance of $1.25 billion of senior notes in July 2007 and with borrowings under our commercial paper program, which was repaid with a portion of the proceeds from the issuance of $1.0 billion of senior notes in August 2007 (Note 4). After recording asset retirement obligation of $32 million, other liabilities and transaction costs of $18 million, the purchase price allocated to proved properties was $2.5 billion and unproved properties was $73 million. The purchase price allocation is preliminary and subject to adjustment pending final determination of the fair value of certain assets acquired.

As part of the acquisition, Dominion retained interests in certain of the acquired properties. Under the terms of the acquisition and the retained interest agreements, Dominion retained the rights to approximately 13 Bcf of gas beginning from the date of acquisition through February 2009 (Note 8).

In October 2007, we announced that we acquired both producing and unproved properties in the Barnett Shale from multiple parties for approximately $550 million. These acquisitions were funded by borrowings under our commercial paper program and are subject to typical post-closing adjustments.

We expect to complete acquisitions of both producing and unproved properties for approximately $1.0 billion during the first quarter of 2008. These acquisitions will be funded both by commercial paper borrowings and by proceeds from the February 2008 common stock offering (Note 9) and are subject to typical post-closing adjustments.

On February 28, 2006, we acquired proved and unproved properties in East Texas and Mississippi from Total E&P USA, Inc. for $300 million. The acquisition was funded by bank borrowings.

On June 30, 2006, we acquired Peak Energy Resources, Inc., which operated gas-producing properties and owned unproved properties in the Barnett Shale in the Fort Worth Basin. The total purchase price was $108 million, which was primarily funded by issuance of 3.2 million shares of common stock valued at $102 million, $5 million cash for additional leasehold interests and $1 million cash for other transaction costs. After recording estimated deferred taxes of $36 million and other liabilities, the purchase price allocated to proved properties was $97 million and unproved properties was $53 million.

In March 2005, we traded nonoperated producing properties owned by us in the San Juan and Permian basins and in Alaska for producing properties owned by ConocoPhillips in the East Texas Freestone Trend, the San Juan Basin and the Permian Basin Goldsmith Field. The properties exchanged by each party had an approximate value of $74 million. We accounted for this transaction as an exchange of similar productive assets used in oil and gas producing activities, under APB Opinion No. 29 and SFAS No. 19, resulting in no gain or loss recognized on the exchange. We operate the properties that we received in this exchange.

To further establish our presence in the Barnett Shale in the Fort Worth Basin, we acquired Antero Resources Corporation on April 1, 2005. Antero Resources owned operated gas-producing properties and unproved properties in the Barnett Shale. In the transaction, we paid cash of $342 million, issued 16.7 million shares of our common stock, and issued warrants that expire April 1, The cash portion of the acquisition was funded with borrowings under our revolving credit facility. At closing, bank debt assumed from Antero Resources was repaid with borrowings under our revolving credit facility.

The following is the final calculation of the purchase price of Antero Resources Corporation and the allocation to assets and liabilities as of April 1, 2005. The fair value of consideration issued is determined as of January 10, 2005, the date the acquisition was announced.

(in millions)	
Consideration issued to Antero Resources stockholders:	
16.7 million shares of common stock (at fair value of $19.78 per share)	$ 330
Warrants to purchase 2.6 million shares of common stock at $20.78 per share (at fair value of $6.51 per warrant)	17
	347
Cash paid	342
Total purchase price	689
Fair value of liabilities assumed:	
Current liabilities	114
Long-term debt	218
Asset retirement obligation	4
Other long-term liabilities	11
Deferred income taxes	225
Total purchase price plus liabilities assumed	$1,261
Fair value of assets acquired:	
Cash and cash equivalents	$ 2
Other current assets	55
Proved properties	634
Unproved properties	180
Other property and equipment, primarily gathering and pipeline assets	35
Acquired gas gathering contracts	140
Goodwill (none deductible for income taxes)	215
Total fair value of assets acquired	$1,261

In May 2005, we acquired producing properties in East Texas and northwestern Louisiana from Plains Exploration & Production Company for an adjusted purchase price of $336 million. The acquisition was funded with borrowings under our revolving credit facility.

In June 2005, we entered an agreement with ExxonMobil Corporation to develop acreage in the northeastern portion of the Piceance Basin in northwest Colorado. Under the terms of the agreement, we have farmed in a 50% working interest ownership in approximately 69,500 contiguous gross acres east of ExxonMobil's Piceance Creek Unit which we operate.

In July 2005, we acquired producing properties in the Permian Basin of West Texas and New Mexico from ExxonMobil Corporation for an adjusted purchase price of $200 million. The acquisition was funded with borrowings under our revolving credit facility.

In September 2005, we traded nonoperated producing properties in the Permian Basin of West Texas for producing properties owned by Occidental Petroleum in the Permian Basin of New Mexico. We accounted for this transaction as an exchange of nonmonetary assets in accordance with SFAS No. 153. This exchange resulted in the recognition of a $10 million gain.

Acquisitions were recorded using the purchase method of accounting. The following presents our unaudited pro forma results of operations for 2007, 2006 and 2005, as if the 2007 Dominion acquisition was made at the beginning of 2006 and 2007, and the 2005 Antero Resources acquisition was made at the beginning of 2005. These pro forma results are not necessarily indicative of future results.

Revenues	$ 5,843	$ 5,212	$ 3,555
Net income	$ 1,718	$ 1,959	$ 1,155
Earnings per common share:			
Basic	$ 3.57	$ 4.10	$ 2.55
Diluted	$ 3.52	$ 4.05	$ 2.50
Weighted average shares outstanding:			
Basic	481.2	477.6	452.2
Diluted	488.2	483.8	461.2

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following are summarized quarterly financial data for the years ended December 31, 2007 and 2006:

	Quarter			
(in millions, except per share data)	1st	2nd	3rd	4th
2007				
Revenues	$1,169	$1,329	$1,421	$1,594
Gross profit (a)	$ 703	$ 777	$ 755	$ 888
Net income	$ 383	$ 432	$ 412	$ 464
Earnings per common share (b)				
Basic	$ 0.83	$ 0.93	$ 0.86	$ 0.96
Diluted	$ 0.82	$ 0.91	$ 0.84	$ 0.95
Average shares outstanding	458.4	464.9	481.1	482.8
2006				
Revenues	$1,215	$1,066	$1,096	$1,199
Gross profit (a)	$ 809	$ 651	$ 659	$ 742
Net income	$ 467	$ 597(c)	$ 367	$ 429
Earnings per common share (b)				
Basic	$ 1.03	$ 1.31	$ 0.80	$ 0.94
Diluted	$ 1.01	$ 1.29	$ 0.79	$ 0.92
Average shares outstanding	454.9	454.7	457.3	457.5

(a) Operating income before general and administrative expense.

(b) Because quarterly earnings per share is based on the weighted average shares outstanding during the quarter, the sum of quarterly earnings per share may not equal earnings per share for the year.

(c) Included in second quarter net income is an after-tax gain on the distribution of Hugoton Royalty Trust units of $292 million (Note 9).

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 millions)	2007	2006	2005
Acquisitions:			
Proved properties	$3,197	$ 561	$1,710
Unproved properties — acquisitions of proved properties (a)	260	83	185
Unproved properties — other	571	142	87
Development (b)	2,529	2,022	1,341
Exploration	257	123	52
Asset retirement obligation accrued upon:			
Acquisition	58	7	24
Development (c)	68	64	29
Total Costs Incurred	$6,940	$3,002	$3,428

(a) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties (Note 13).

(b) Includes capitalized interest of $30 million in 2007, $18 million in 2006 and $6 million in 2005.

(c) Includes revisions of $39 million in 2007, $36 million in 2006 and $16 million in 2005.

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. Proved reserves exclude volumes deliverable to others under production payments or retained interests.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of year-end prices for oil and gas and year-end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Year-end prices are not adjusted for the effect of hedge derivatives. Discounted future net cash flows are calculated using a 10% rate. Estimated future income taxes are calculated by applying year-end statutory rates to future pre-tax net cash flows, less the tax basis of related assets and applicable tax credits.

Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year-end costs and discounted at the 10% rate. As required by SFAS No. 143, such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values as of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired (Note 5).

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

Proved Reserves

(in millions)	Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)	Natural Gas Equivalents (Mcfe)
December 31, 2004	4,714.5	38.5	152.5	5,860.3
Revisions	4.0	5.3	12.1	108.5
Extensions, additions and discoveries	986.6	4.9	34.2	1,221.2
Production	(377.1)	(3.8)	(14.3)	(485.5)
Purchases in place	803.4	2.8	31.1	1,007.1
Sales in place	(45.8)	(0.3)	(6.9)	(89.4)
December 31, 2005	6,085.6	47.4	208.7	7,622.2
Revisions	(94.9)	1.8	0.1	(83.2)
Extensions, additions and discoveries	1,416.8	4.0	20.3	1,562.6
Production	(433.0)	(4.4)	(16.4)	(557.6)
Purchases in place	157.9	4.2	3.3	202.9
Sales in place (a)	(188.2)	-	(1.6)	(198.3)
December 31, 2006	6,944.2	53.0	214.4	8,548.6
Revisions	(46.3)	10.2	15.5	108.2
Extensions, additions and discoveries	1,797.5	5.8	18.4	1,942.5
Production	(532.1)	(4.9)	(17.2)	(664.8)
Purchases in place	1,278.8	2.7	11.3	1,362.7
Sales in place	(1.0)	-	(1.2)	(8.2)
December 31, 2007	9,441.1	66.8	241.2	11,289.0

(a) Includes effect of distribution of Hugoton Royalty Trust units (Note 9).

The additions to our proved reserves from extensions, additions and discoveries in the last three years are due to the success of our development drilling program. See a summary of our drilling activity over the last three years in Part I, Items 1 and 2, Business and Properties — Exploration and Production Data — Drilling Activity.

(in millions)	Gas (Mcf)	Liquids (Bbls)	Oil (Bbls)	(Mcfe)
December 31, 2004	3,252.7	30.0	134.4	4,239.1
December 31, 2005	4,033.1	36.5	168.5	5,262.9
December 31, 2006	4,481.6	40.1	167.3	5,725.9
December 31, 2007	6,031.5	52.9	184.8	7,457.7

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

	December 31		
(in millions)	2007	2006	2005
Future cash inflows	$ 86,080	$ 51,477	$ 69,732
Future costs:			
Production	(22,066)	(14,958)	(15,660)
Development	(6,065)	(4,260)	(3,175)
Future income tax	(18,423)	(10,251)	(16,823)
Future net cash flows	39,526	22,008	34,074
10% annual discount	(19,988)	(11,180)	(16,980)
Standardized measure	$ 19,538	$ 10,828	$ 17,094

Changes in Standardized Measure of Discounted Future Net Cash Flows

(in millions)	2007	2006	2005
Standardized measure, January 1	$ 10,828	$ 17,094	$ 8,402
Revisions:			
Prices and costs	7,958	(10,687)	8,506
Quantity estimates	1,868	960	708
Accretion of discount	970	1,511	741
Future development costs	(3,082)	(2,479)	(2,167)
Income tax	(3,749)	4,090	(4,550)
Production rates and other	-	3	(2)
Net revisions	3,965	(6,602)	3,236
Extensions, additions and discoveries	3,541	2,248	3,723
Production	(4,359)	(3,629)	(2,744)
Development costs	2,299	1,917	1,128
Purchases in place (a)	3,286	396	3,527
Sales in place (b)	(22)	(596)	(178)
Net change	8,710	(6,266)	8,692
Standardized measure, December 31	$ 19,538 (c)	$ 10,828 (d)	$ 17,094 (e)

(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. Included in 2006 is the effect of distribution of Hugoton Royalty Trust units (Note 9).

(c) The December 31, 2007 standardized measure includes a reduction of $43 million ($68 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2007 includes a liability of $453 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions as required by SFAS No. 143, as described above.

(d) The December 31, 2006 standardized measure includes a reduction of $29 million ($46 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2006 includes a liability of $307 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions as required by SFAS No. 143, as described above.

(e) The December 31, 2005 standardized measure includes a reduction of $22 million ($34 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2005 includes a liability of $223 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions as required by SFAS No. 143, as described above.

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

Year-end average realized gas prices used in the estimation of proved reserves and calculation of the standardized measure were $6.39 for 2007, $5.46 for 2006, $9.26 for 2005 and $5.69 for 2004. Year-end average realized natural gas liquids prices were $60.24 for 2007, $31.96 for 2006, $36.33 for 2005 and $28.24 for 2004. Year-end average realized oil prices were $91.19 for 2007, $55.47 for 2006, $57.02 for 2005 and $41.03 for 2004.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control — Integrated Framework*. Our management has concluded that, based on these criteria, we have maintained in all material respects, effective internal control over financial reporting as of December 31, 2007.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected.

February 26, 2008

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

We have audited the accompanying consolidated balance sheets of XTO Energy Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated income statements, statements of cash flows and statements of stockholders' equity for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by 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 XTO Energy Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*, on January 1, 2006.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), XTO Energy Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 25, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP
Dallas, Texas
February 25, 2008

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

We have audited XTO Energy Inc.'s internal control over financial reporting, as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, XTO Energy Inc. and subsidiaries maintained in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of XTO Energy Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated income statements, statements of cash flows and statements of stockholders' equity for each of the years in the three-year period ended December 31, 2007, and our report dated February 25, 2008 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP
Dallas, Texas
February 25, 2008

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 26th day of February 2008.

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 26th day of February 2008.

Principal Executive Officers (and Directors)

BOB R. SIMPSON

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

KEITH A. HUTTON

Keith A. Hutton, President

VAUGHN O. VENNERBERG II

Vaughn O. Vennerberg II, Senior
Executive Vice President and Chief of Staff

Directors

WILLIAM H. ADAMS III

William H. Adams III

LANE G. COLLINS

Lane G. Collins

PHILLIP R. KEVIL

Phillip R. Kevil

JACK P. RANDALL

Jack P. Randall

SCOTT G. SHERMAN

Scott G. Sherman

HERBERT D. SIMONS

Herbert D. Simons

Principal Financial Officer

LOUIS G. BALDWIN

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

Principal Accounting Officer

BENNIE G. KNIFFEN

Bennie G. Kniffen, Senior Vice President
and Controller

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
2.1 +	Agreement and Plan of Merger dated January 9, 2005 among XTO Energy Inc., XTO Barnett Inc., and Antero Resources Corporation (incorporated by reference to Exhibit 2.2 to Form 10-K for the year ended December 31, 2004)
2.2 +	Amendment No. 1 to Agreement and Plan of Merger dated February 3, 2005 among XTO Energy Inc., XTO Barnett Inc., and Antero Resources Corporation (incorporated by reference to Exhibit 2.3 to Form 10-K for the year ended December 31, 2004)
2.3 +	Amendment No. 2 to Agreement and Plan of Merger dated March 22, 2005 among the Company, XTO Barnett Inc., XTO Barnett LLC and Antero Resources Corporation (incorporated by reference to Exhibit 2.1 to Form 8-K filed March 28, 2005)
2.4 +	Amendment No. 3 to Agreement and Plan of Merger dated March 31, 2005 among the Company, XTO Barnett Inc., XTO Barnett LLC and Antero Resources Corporation (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 5, 2005)
2.5 +	Gulf Coast/Rockies/San Juan Package Purchase Agreement dated as of June 1, 2007 between Dominion Exploration & Production, Inc., Dominion Energy, Inc., Dominion Oklahoma Texas Exploration & Production, Inc., Dominion Reserves, Inc., LDNG Texas Holdings, LLC and DEPI Texas Holdings, LLC. as Sellers and XTO Energy Inc. as Buyer. (incorporated by reference to Exhibit 2.1 to Form 8-K filed August 6, 2007)
3.1	Restated Certificate of Incorporation of the Company, as restated on June 21, 2006 (incorporated by reference to Exhibit 3.1 to Form 10-Q for the quarter ended June 30, 2006)
3.2	Amended and Restated Bylaws of the Company dated November 18, 2003 (incorporated by reference to Exhibit 3.1 to Form 10-Q for the quarter ended March 31, 2006)
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 7 1/2% Senior Notes due 2012 (incorporated by reference to Exhibit 4.2 to Form 10-K for the year ended December 31, 2002)
4.3	Second Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 7 1/2% Senior Notes due 2012 (incorporated by reference to Exhibit 4.3 to Form 10-Q for the quarter ended March 31, 2006)
4.4	Preferred Stock Purchase Rights Agreement dated August 25, 1998 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)
4.6	Registration Rights Agreement among the Company and partners of Cross Timbers Oil Company, L.P. (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S-1, File No. 33-59820)
4.7	Indenture dated as of April 23, 2003 between the Company and the Bank of New York, as Trustee for the 6 1/4% Senior Notes due 2013 (incorporated by reference to Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2003)
4.8	First Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 6 1/4% Senior Notes due 2013 (incorporated by reference to Exhibit 4.4 to Form 10-Q for the quarter ended March 31, 2006)

4.9 Registration Rights Agreement dated April 23, 2003 between the Company and certain Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to Form 10-Q for the quarter ended March 31, 2003)

4.10 Indenture for Senior Debt Securities dated as of January 22, 2004 between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8-K filed January 16, 2004)

4.11 First Supplemental Indenture dated as of January 22, 2004 between the Company and the Bank of New York, as Trustee for the 4.90% Senior Notes due 2014 (incorporated by reference to Exhibit 4.3.2 to Form 8-K filed January 16, 2004)

4.12 Second Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 4.90% Senior Notes due 2014 (incorporated by reference to Exhibit 4.5 to Form 10-Q for the quarter ended March 31, 2006)

4.13 Indenture dated as of September 23, 2004 between the Company and the Bank of New York, as Trustee for the 5% Senior Notes due 2015 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 24, 2004)

4.14 First Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 5% Senior Notes due 2015 (incorporated by reference to Exhibit 4.6 to Form 10-Q for the quarter ended March 31, 2006)

4.15 Indenture for Senior Debt Securities dated as of April 13, 2005 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 12, 2005)

4.16 First Supplemental Indenture dated as of April 13, 2005 between the Company and the Bank of New York, as Trustee for 5.30% Senior Notes due 2015 (incorporated by reference to Exhibit 4.3.2 to Form 8-K filed April 12, 2005)

4.17 Second Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 5.30% Senior Notes due 2015 (incorporated by reference to Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2006)

4.18 Third Supplemental Indenture dated as of March 30, 2006 between the Company and The Bank of New York Trust Company, as Trustee, for 5.65% Senior Notes due 2016 and 6.10% Senior Notes due 2036 (incorporated by reference to Exhibit 4.2 to Form 10-Q for the quarter ended March 31, 2006)

4.19 Registration Rights Agreement dated April 1, 2005 among XTO Energy Inc. and the security holders of Antero Resources Corporation (incorporated by reference to Exhibit 4.1 to Form 10-Q for the quarter ended June 30, 2005)

4.20 Indenture for Senior Debt Securities dated as of July 19, 2007 between the Company and the Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8-K filed July 16, 2007)

4.21 First Supplemental Indenture dated as of July 19, 2007 between the Company and the Bank of New York Trust Company, N.A., as Trustee for 5.90% Senior Notes due 2012, 6.25% Senior Notes due 2017 and 6.75% Senior Notes due 2037 (incorporated by reference to Exhibit 4.3.2 to Form 8-K filed July 16, 2007)

10.1* Amended and Restated Employment Agreement between the Company and Bob R. Simpson, dated May 17, 2000 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2000)

10.2* Amendment to Amended and Restated Employment Agreement between the Company and Bob R. Simpson, dated August 20, 2002 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2002)

10.3* Employment Agreement between the Company and Bob R. Simpson, dated May 16, 2006 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2006)

10.4* Amendment to Employment Agreement between XTO Energy Inc. and Bob R. Simpson, dated December 31, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K filed January 7, 2008)

10.5 Employment Agreement between the Company and Keith A. Hutton, dated May 16, 2006 (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2006)

10.6* Employment Agreement between the Company and Vaughn O. Vennerberg II, dated May 16, 2006 (incorporated by reference to Exhibit 10.4 to Form 10-Q for the quarter ended June 30, 2006)

10.7* Amended and Restated Employment Agreement between the Company and Steffen E. Palko, dated May 17, 2000 (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2000)

10.8* 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)

10.9* 1998 Stock Incentive Plan, as amended March 17, 2004 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2004)

10.10* XTO Energy Inc. Amended and Restated 2004 Stock Incentive Plan (incorporated by reference to Appendix B to the Proxy Statement dated April 13, 2006 for the Annual Meeting of Stockholders held May 16, 2006)

10.11* XTO Energy Inc. Amended and Restated 2004 Stock Incentive Plan (as amended and restated through November 21, 2006) (incorporated by reference to Exhibit to 10.10 to Form 10-K for the year ended December 31, 2006)

10.12* Form of Nonqualified Stock Option Agreement for Employees under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed November 22, 2004)

10.13* Form of Nonqualified Stock Option Agreement for Employees with Employment Agreements under the Amended and Restated 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2006)

10.14* Form of Stock Award Agreement for Employees under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed November 22, 2004)

10.15* Form of Nonqualified Stock Option Agreement for Non-Employee Directors under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed November 22, 2004)

10.16* Form of Stock Award Agreement for Non-Employee Directors under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed November 22, 2004)

10.17* Form of Stock Grant Agreement for Non-Employee Directors under Section 11 of the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 22, 2005)

10.18* Form of Stock Grant Agreement (With Restrictions) for Non-Employee Directors under Section 11 of the 2004 Stock Incentive Plan

10.19* Amended Employee Severance Protection Plan, as amended February 15, 2000 (incorporated by reference to Exhibit 10.14 to Form 10-K for the year ended December 31, 1999)

10.20* Amendment to Amended Employee Severance Protection Plan, as amended August 20, 2002 (incorporated by reference to Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2002)

10.21* Second Amended and Restated Employee Severance Protection Plan, as amended August 15, 2006 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2006)

10.22* Amended and Restated Management Group Employee Severance Protection Plan, as amended February 15, 2000 (incorporated by reference to Exhibit 10.13 to Form 10-K for the year ended December 31, 1999)

10.23* 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)

10.24* Second Amended and Restated Management Group Employee Severance Protection Plan, as amended August 15, 2006 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2006)

10.25 Outside Directors Severance Plan dated August 20, 2002 (incorporated by reference to Exhibit 10.8 to Form 10-Q for the quarter ended September 30, 2002)

10.26* Amended and Restated Outside Directors Severance Plan, as amended August 15, 2006 (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2006)

10.27* Form of Amended and Restated Agreement (relating to change in control) between the Company and Bob R. Simpson, Steffen E. Palko, Louis G. Baldwin, Keith A. Hutton and Vaughn O. Vennerberg II, dated October 15, 2004 (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 21, 2004)

10.28* Form of Amendment No. One to Amended and Restated Agreement (relating to change in control) between the Company and Bob R. Simpson, Louis G. Baldwin, Keith A. Hutton and Vaughn O. Vennerberg, dated November 21, 2006 (incorporated by reference to Exhibit to 10.26 to Form 10-K for the year ended December 31, 2006)

10.29* Amendment Number Two to Amended and Restated Agreement (relating to change in control) between XTO Energy Inc. and Bob R. Simpson, dated December 31, 2007 (incorporated by reference to Exhibit 10.2 to Form 8-K filed January 7, 2008)

10.30* Agreement (relating to change in control) between the Company and Timothy L Petrus, dated November 21, 2006 (incorporated by reference to Exhibit 10.27 to Form 10-K for the year ended December 31, 2006)

10.31* Consulting and Non-Competition Agreement dated April 1, 2005 between the Company and Steffen E. Palko (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 5, 2005)

10.32* Form of Indemnification Agreement dated November 15, 2005 between the Company and each director, executive officer and certain other officers (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 18, 2005)

10.33* Form of Stock Award Agreement (Restricted Shares) for Employees under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.30 to Form 10-K for the year ended December 31, 2006)

10.34* Description of Matching Charitable Contribution Program for officers and directors

10.35 Amended and Restated 5-Year Revolving Credit Agreement dated April 1, 2005 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2005)

10.36 First Amendment to Five-Year Revolving Credit Agreement dated March 10, 2006 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, 2006)

10.37 Second Amendment to Five-Year Revolving Credit Agreement dated October 25, 2006 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2006)

10.38 Third Amendment to 5-Year Revolving Credit Agreement dated March 19, 2007 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed March 23, 2007)

10.39 Fourth Amendment to 5-Year Revolving Credit Agreement dated February 6, 2008 between the Company and certain commercial banks named therein

10.40 Term Loan Credit Agreement dated November 10, 2004 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.20 to Form S-4 dated December 13, 2004)

10.41 First Amendment to Term Loan Agreement dated April 1, 2005 between the Company and certain banks named therein (incorporated by reference to Exhibit 10.4 to Form 10-Q for the quarter ended March 31, 2005)

10.42 Second Amendment to Term Loan Agreement dated March 10, 2006 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2006)

10.43 Third Amendment to Term Loan Agreement dated March 19, 2007 between the Company and certain banks named therein (incorporated by reference to Exhibit 10.2 to Form 8-K filed March 23, 2007)

10.44 Fourth Amendment to Term Loan Agreement dated February 6, 2008 between the Company and certain banks named therein

10.45 Form of Commercial Paper Dealer Agreement dated October 27, 2006 between the Company and each of Lehman Brothers Inc., Citigroup Global Markets Inc., Goldman, Sachs & Co. and JPMorgan Securities Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 2, 2006)

10.46 Issuing and Paying Agency Agreement dated October 27, 2006 between the Company and JPMorgan Chase bank, National Association (incorporated by reference to Exhibit 10.2 to Form 8-K filed November 2, 2006)

10.47 Firm Intrastate Gas Transportation Agreement dated July 1, 2005 between the Company, XTO Resources I, LP and Energy Transfer Fuel, LP (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2005) (Material has been omitted from this Exhibit pursuant to an order of confidential treatment and the omitted material has been separately filed with the Securities and Exchange Commission.)

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 Consent of Miller and Lents, Ltd.

31.1 Chief Executive Officer Certification required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934

31.2 Chief Financial Officer Certification required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934

32.1 Chief Executive Officer and Chief Financial Officer Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

+ All schedules and similar attachments have been omitted. The Company agrees to furnish supplementally a copy of the omitted schedules and similar attachments to the Securities and Exchange Commission upon request.

* Management contract or compensatory plan

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

Directors

(a) Audit Committee
(b) Compensation Committee
(c) Corporate Governance and Nominating Committee

Bob R. Simpson
Chairman and
Chief Executive Officer
XTO Energy Inc.

Keith A. Hutton
President
XTO Energy Inc.

Vaughn O. Vennerberg II
Senior Executive Vice President
and Chief of Staff
XTO Energy Inc.

William H. Adams III (a, b, c)
Chairman and a Principal Owner
Texas Appliance Supply, Inc.

Dr. Lane G. Collins (a, b, c)
Professor Emeritus of Accounting
Baylor University

Phillip R. Kevil (a, c)
Retired Executive
Certified Public Accountant

Jack P. Randall
Cofounder
Randall & Dewey
Division of Jefferies & Company, Inc.

Scott G. Sherman (a, b, c)
Owner
Sherman Enterprises

Herbert D. Simons (a, b, c)
Retired Tax Attorney
Certified Public Accountant

Advisory Directors

Louis G. Baldwin
Executive Vice President and
Chief Financial Officer
XTO Energy Inc.

Timothy L. Petrus
Executive Vice President,
Acquisitions
XTO Energy Inc.

Executive Officers

Bob R. Simpson
Chairman and
Chief Executive Officer

Keith A. Hutton
President

Vaughn O. Vennerberg II
Senior Executive Vice President
and Chief of Staff

Louis G. Baldwin
Executive Vice President and
Chief Financial Officer

Timothy L. Petrus
Executive Vice President,
Acquisitions

Senior Officers

Brent W. Clum
Senior Vice President and
Treasurer

James L. Death
Senior Vice President,
Land

Nick J. Dungey
Senior Vice President,
Natural Gas Operations

Ken K. Kirby
Senior Vice President, Operations
Eastern Region

Bennie G. Kniffen
Senior Vice President and
Controller

Frank G. McDonald
Senior Vice President, General
Counsel and Assistant Secretary

F. Terry Perkins, Jr.
Senior Vice President,
Reservoir Engineering

Mark J. Pospisil
Senior Vice President,
Geology & Geophysics

Edwin S. Ryan, Jr.
Senior Vice President,
Land Administration

Terry L. Schultz
Senior Vice President,
Marketing

Douglas C. Schultze
Senior Vice President, Operations
Mid-Continent

Gary D. Simpson
Senior Vice President,
Investor Relations & Finance

Kenneth F. Staab
Senior Vice President,
Engineering

Mark A. Stevens
Senior Vice President,
Taxation

Other Officers

Scott T. Agosta
Vice President,
Financial Reporting

Virginia N. Anderson
Vice President and
Corporate Secretary

Kathy L. Cox
Vice President,
Associate General Counsel
and Assistant Secretary

Delbert L. Craddock
Vice President, Operations
San Juan Basin

Kyle M. Hammond
Vice President, Operations
Permian Division

Nina C. Hutton
Vice President,
Environmental, Health
and Safety

Timothy B. McIlwain
Vice President, Operations
Fort Worth Division

L. Frank Thomas III
Vice President,
Information Technology

T. Joy Webster
Vice President,
Facilities

Karen Wilson
Vice President,
Human Resources

William B. D. Butler
Assistant Treasurer

Martha L. Montgomery
Assistant Controller

Corporate Headquarters

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

Operations Offices

EASTERN REGION
6141 Paluxy Drive
Tyler, Texas 75703
(903) 939-1200

SAN JUAN & RATON
382 Road 3100
Aztec, New Mexico 87410
(505) 333-3100

ARKOMA
P.O. Box 218
1541 Airport Road
Ozark, Arkansas 72949
(479) 667-4819

PERMIAN
200 N. Loraine, Suite 800
Midland, Texas 79701
(915) 682-8873

MID-CONTINENT
210 Park Avenue, Suite 2350
Oklahoma City, Oklahoma 73102
(405) 232-4011

FORT WORTH BASIN
210 West 6th Street
Fort Worth, Texas 76102
(817) 810-0402

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

HOUSTON
22485 Tomball Parkway
Suite 200
Houston, Texas 77070-1530
(281) 257-7316

Annual Meeting

Tuesday, May 20, 2008 at 10 a.m.
Fort Worth Convention Center
1201 Houston Street
Ballroom C
Fort Worth, Texas 76102

Independent Auditors

KPMG LLP
Dallas, Texas

Transfer Agents and Registrars

Common Stock:
BNY Mellon Shareowner Services
480 Washington Boulevard
Jersey City, New Jersey 07310-1900
www.bnymellon.com/shareowner/isd

Senior Notes:
The Bank of New York Trust Company, N.A.
Corporate Trust Division
New York, New York

Form 10-K

Additional copies of the Company's Annual Report on Form 10-K, Notice of Annual Meeting of Stockholders and Proxy Statement for Annual Meeting of Stockholders 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.

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.

U.S. Shareholders
(888) 877-2892

TDD for Hearing Impaired
(800) 231-5469
(Domestic and Foreign)

Foreign Shareholders
(201) 680-6578

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 contact: BNY Mellon Shareowner Services at (866) 353-7849.

Web Site

www.xtoenergy.com

Certifications

The certifications of the Chief Executive Officer and Chief Financial Officer of XTO Energy required by Section 302 of the Sarbanes-Oxley Act of 2002 have been filed as Exhibits 31.1 and 31.2, respectively, to the Company's Form 10-K for the fiscal year ended December 31 2007.

As required by the New York Stock Exchange (NYSE) listing standards, an unqualified annual certification indicating compliance with the corporate governance listing standards was signed by the Company's Chief Executive Officer and submitted to the NYSE on May 21, 2007.

The following terms are considered non-GAAP measures as defined by the Securities and Exchange Commission. Management uses these measures to evaluate the Company's performance versus the performance of other oil and gas producing companies, as well as to evaluate potential acquisitions.

Drill Bit Finding Costs
The total of costs incurred for development, exploration and acquisitions of unproved properties – other[a]

Drill Bit Reserves
The total of proved reserve extensions, additions and discoveries and revisions[a,b]

Drill Bit Reserve Finding Cost
Drill Bit Finding Costs divided by Drill Bit Reserves

Free Cash Flow
Operating Cash Flow less total maintenance and development expenditures required to maintain current production levels

Operating Cash Flow
Cash provided by operating activities before changes in operating assets and liabilities, exploration expense and significant cash flow effects of non-recurring items. Because of these adjustments, this cash flow statistic is different from cash provided by operating activities, as disclosed under GAAP and reconciled to operating cash flow as follows:

(in millions)	2007	2006	2005	2004	2003
Cash provided by operating activities	$ 3,639	$ 2,859	$ 2,094	$ 1,217	$ 794
Changes in operating assets and liabilities	72	(5)	158	58	(4)
Exploration expense[c]	31	13	24	11	2
Current tax related to gain on distribution of royalty trust units	–	211	–	–	–
Operating cash flow	$ 3,742	$ 3,078	$ 2,276	$ 1,286	$ 792

Management believes 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 primarily related to the timing of cash receipts and disbursements, which can vary from period-to-period because of conditions the Company 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 the Company's capital budget.
- Adjustment for the significant cash flow effects of non-recurring items.

Upside Potential or Additional Resource
Reserves beyond proved reserves[a], which includes probable and possible reserves that are potentially recoverable through additional drilling or recovery techniques. Only proved reserves are disclosed in financial statements prepared in accordance with GAAP, and SEC guidelines prohibit disclosure of these potentially recoverable reserves in filings with the SEC. Management believes it is appropriate to disclose these potentially recoverable reserves in certain communications with investors to provide reserve estimates associated with our inventory of future drill well locations.

a As disclosed in Note 15 to Consolidated Financial Statements
b As calculated on a natural gas equivalent (Mcfe) basis
c Net of dry hole expense excluded from cash provided by operating activities beginning in 2006

Bbls	Barrels (of oil or NGLs)
Bcf	Billion cubic feet (of gas)
Bcfe	Billion cubic feet of natural gas equivalent
CBM	Coal bed methane
LNG	Liquified natural gas
MBbls	Thousand barrels (of oil or NGLs)
MMBOE	Million barrels of oil equivalent
Mcf	Thousand cubic feet (of gas)
Mcfe	Thousand cubic feet of natural gas equivalent
MMcf	Million cubic feet (of gas)
MMcfe	Million cubic feet of natural gas equivalent
Tcfe	Trillion cubic feet of natural gas equivalent

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

XTO ENERGY INC.

COMPANY PROFILE

XTO Energy Inc. is a domestic energy producer engaged in the acquisition, development and exploration of long-lived, high-quality natural gas and oil properties. Established in 1986 as Cross Timbers Oil Company, XTO now owns interests in 25,163 wells in Texas, New Mexico, Arkansas, Oklahoma, Kansas, Wyoming, Colorado, Alaska, Utah, Louisiana, Mississippi and Montana. Headquarters are located in Fort Worth, Texas, and at year end, the Company had 2,361 employees. As of December 31, 2007, XTO Energy owns 11.29 Tcfe of proved reserves of which 66% are proved developed. Gas volumes account for 84% of total reserves. Under SEC guidelines, the present value before income tax, discounted at 10%, of the Company's proved reserves equals $29.2 billion. Reserves are engineered each year by the independent engineering firm, Miller and Lents, Ltd. From the IPO in 1993 through 2007, the Company's stock price has moved from $13 to $751 per share, excluding adjustments for stock splits. XTO Energy has created two other publicly traded investments: Cross Timbers Royalty Trust (NYSE:CRT) and Hugoton Royalty Trust (NYSE:HGT) which went public in 1992 and 1999, respectively.

This Annual Report, other than historical financial information, contains forward-looking statements regarding future value creation, growth in production and reserves, cash flow, economic margins, proved reserves, reserve potential, identified upsides, captured resources, captured potential, use of free cash flow, availability of properties for "bolt-on" acquisitions, economic returns, industry performance, industry prosperity, revenues, inventory of drilling locations, availability of oil and natural gas supply, demand for oil and natural gas, future stock performance, oil and natural gas prices and other matters subject to a number of risks and uncertainties that are detailed in the Company's Annual Report on Form 10-K for the year ended December 31, 2007, which is incorporated by this reference as though fully set forth herein. Although the Company believes that the expectations reflected in such statements are reasonable based on current available information, there is no assurance that these goals and projections can or will be met.

The Securities and Exchange Commission has generally permitted oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use the terms reserve "potential" or "upside", "captured resources", "captured potential" or other descriptions of volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the Company.

XTO ENERGY INC.

810 Houston Street • Fort Worth, Texas 76102

xtoenergy.com

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