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

Form 10-K

(X) Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2004

Commission file number 1-08246

Southwestern Energy Company

(Exact name of Registrant as specified in its charter)

Arkansas	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2350 North Sam Houston Parkway East, Suite 300, Houston, Texas 77032
(Address of principal executive offices, including zip code)

(281) 618-4700
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock Par Value $0.10	New York Stock Exchange

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

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

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

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

The aggregate market value of the voting stock held by non-affiliates of the Registrant was $1,016,483,812 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2004, of $28.67. For purposes of this calculation, the Registrant has assumed that its directors and executive officers are affiliates.

The number of shares outstanding as of March 3, 2005, of the Registrant's Common Stock, par value $0.10, was 36,456,066.

Document incorporated by reference: Portions of the Registrant's Definitive Proxy Statement to be filed with respect to the Annual Meeting of Shareholders to be held on May 11, 2005 are incorporated by reference into Part III of this Form 10-K.

SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2004

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This Annual Report on Form 10-K includes certain statements that may be deemed to be "forward-looking" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to "Risk Factors" in Item 1 of Part I and to "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of Part II of this Form 10-K for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements.

The electronic version of this Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or the SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, Compensation, Nominating and Retirement Committees of our Board of Directors are available on our website, and are available in print free of charge to any shareholder upon request.

PART I

ITEM 1. BUSINESS OVERVIEW

Southwestern Energy Company is an integrated energy company primarily focused on the exploration and production of natural gas. We were organized under the laws of Arkansas over 75 years ago and originally operated as a local gas distribution company. Today, we are an exempt holding company under the Public Utility Holding Company Act of 1935, conduct our primary activities through four wholly-owned subsidiaries and derive the vast majority of our operating income and cash flow from our natural gas and oil exploration and production, or E&P, business. In February 2001, we relocated our corporate headquarters from Fayetteville, Arkansas to Houston, Texas. All of our operations are located within the United States. We operate principally in three segments:

1. *Exploration and Production* – Our primary business is natural gas and oil exploration, development and production, with our operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We engage in natural gas and oil exploration and production through our wholly-owned subsidiaries, SEECO, Inc., Southwestern Energy Production Company (which we refer to as SEPCO), Diamond "M" Production Company and Overton Partners, L.L.C., a wholly-owned subsidiary of SEPCO. SEECO operates exclusively in Arkansas, holds a large base of both developed and undeveloped gas reserves and conducts an ongoing drilling program in the Arkansas part of the Arkoma Basin. SEPCO conducts development drilling and exploration programs in the Arkoma Basin, the Permian Basin of Texas and New Mexico, and in Louisiana and East Texas. Diamond "M" has interests in properties in the Permian Basin of Texas. Overton Partners owns an interest in Overton Partners, L.P., a limited partnership formed in 2001 to drill and complete 14 development wells in SEPCO's Overton Field in East Texas.

2. *Natural Gas Distribution* – We are also engaged in the gathering, distribution and transmission of natural gas. Our wholly-owned subsidiary, Arkansas Western Gas Company, which we refer to as Arkansas Western, operates integrated natural gas distribution systems in northern Arkansas serving approximately 145,000 retail customers. Arkansas Western is the largest single purchaser of SEECO's gas production.

3. *Marketing* – As a complement to our other businesses, we provide marketing services in each of our core areas of operation. Our gas marketing subsidiary, Southwestern Energy Services Company, was formed in 1996 to better enable us to capture downstream opportunities which arise through marketing and transportation activity.

Our E&P business has increasingly contributed to our financial results primarily due to the general increase in natural gas and crude oil commodity prices and the growth in our production volumes. In 2004, 90% of our operating income and earnings before interest, taxes, depreciation, depletion and amortization, or EBITDA, were generated from our E&P business. Our natural gas distribution and marketing and transportation businesses each generated 5% of our operating income and generated 6% and 4% of our EBITDA in 2004, respectively. In 2003, our E&P business generated 87% of our operating income and EBITDA, while the natural gas distribution and marketing and transportation businesses generated 7% and 6% of our operating income and 9% and 4% of our EBITDA, respectively. In 2002, our E&P, natural gas distribution and marketing and transportation businesses generated 78%, 16% and 6% of our operating income, respectively, and 83%, 14% and 3% of our EBITDA, respectively. We refer you to "Business Overview—Other Items—Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our net income as derived from our audited financial information.

Our Business Strategy

Our business strategy is focused on providing long-term growth in the net asset value of our business. Within the E&P segment, we prepare economic analyses for each of our drilling and acquisition opportunities and rank them based upon the expected present value added for each dollar invested, which we refer to as PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. We target creating at least $1.30 of discounted pre-tax PVI for each dollar we invest in our E&P business. Our actual PVI results are utilized to help determine the allocation of our future capital investments. We are also focused on creating and capturing additional value beyond the wellhead through our natural gas distribution, marketing and transportation businesses. To further our business strategy, we provide stock and cash incentives for our key employees. Cash incentives are based on the achievement of certain overall performance targets as well as segment specific measures. For eligible employees in our E&P segment, these measures include production, proved reserve additions, lease operating expenses and general and administrative expenses per unit of production and PVI added per dollar invested.

The key elements of our E&P business strategy are:

- *Continue to Exploit and Develop Existing Asset Base*. We seek to maximize the value of our existing asset base by developing and exploiting properties that have production and reserve growth potential while also controlling per unit production costs. We intend to add proved reserves and increase production through the use of advanced technologies, including detailed technical analysis of our properties, and by drilling infill locations and selectively recompleting existing wells. We also plan to drill step-out wells to expand known field limits.

- *Focus on Growth Through New Exploration and Development Activities*. We are focused on increasing reserves and production through the drillbit. As part of this effort, we actively seek to develop natural gas and oil plays as well as other new exploration projects with significant exploration and exploitation potential. We have personnel dedicated to the research and identification of active and potential plays, focusing on both conventional exploration plays and unconventional plays (including coal bed methane, shale gas and basin-centered gas) as well as the technological aspects such as horizontal drilling and fracture techniques. New prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria. In August 2004, we announced that we are testing a new unconventional shale gas play on the Arkansas side of the Arkoma Basin. This play, which we refer to as the "Fayetteville Shale play," was an outgrowth of our focus on new exploration and development projects.

- *Rationalize Our Property Portfolio.* We actively pursue opportunities to reduce production costs of our properties. We continually seek to rationalize our portfolio of E&P assets by selling marginal properties in an effort to reduce production costs and improve overall return.

- *Acquiring Selective Properties*. We selectively review opportunities to acquire producing properties and leasehold acreage, focusing in particular on the regions where we have existing operations. In addition, we seek to acquire operational control of properties that we believe may have significant unrealized exploration and exploitation potential. In 2004, we purchased 5.8 Bcfe of proved reserves for $14.2 million at an average cost of $2.45 per Mcfe. Almost all of this investment related to the acquisition of additional working interest in our River Ridge discovery in the Permian Basin. In 2003 and 2002, we invested $3.0 million and $3.1 million for the acquisition of 1.1 Bcfe of proved reserves and 6.6 Bcfe of proved reserves, respectively.

Recent Developments

Amended and Restated Credit Facility and Rating Downgrade. In January 2005, we amended and restated our $300 million revolving credit facility that was due to expire in January 2007, increasing the borrowing capacity to $500 million and extending the expiration to January 2010. The amended and restated revolving credit facility replaced the $300 million credit facility and another smaller credit facility. As of March 3, 2005, we had approximately $420 million of available capacity under this revolving credit facility. On January 3, 2005, Standard & Poor's Ratings Services lowered our corporate credit rating to 'BBB-' from 'BBB'. We continue to be rated Ba2 by Moody's.

Utility Files for Rate Adjustment. Our utility filed for a $9.7 million annual rate increase with the Arkansas Public Service Commission, or APSC, in December 2004. The APSC has ten months to review the filing and determine the amount of the increase, if any. Any rate increase allowed would likely be implemented in the fourth quarter of 2005.

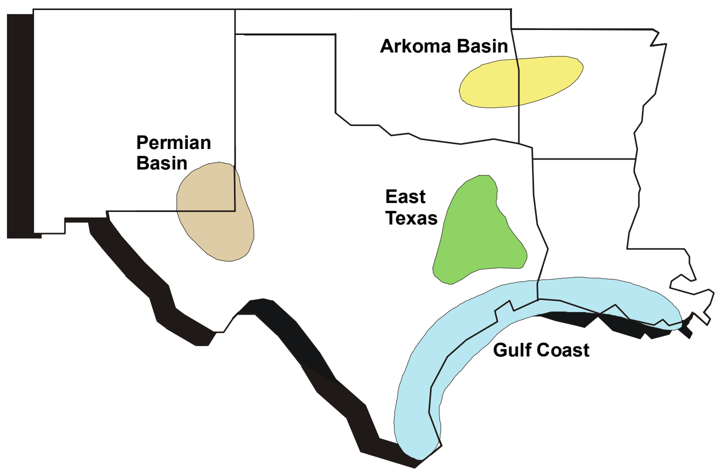
2005 Planned Capital Expenditures and Guidance. In December 2004, we announced a planned capital investment program for 2005 of up to $352.7 million, an increase of 20% over our 2004 capital program. Our 2005 capital program includes up to $339.0 million for our E&P segment and $13.7 million for improvements to our utility systems and for other corporate purposes. The increased capital program is expected to be funded by internally-generated cash flow and borrowings under our revolving credit facility. We also announced our targeted 2005 oil and gas production of approximately 61.0 to 63.0 Bcfe, an increase of approximately 13% to 17% over our production in 2004, our estimates for certain expenses and ranges for certain financial results under various commodity price scenarios.

Announcement of Fayetteville Shale Play. On August 17, 2004, we announced our Fayetteville Shale play. Our acreage position in the play at December 31, 2004, was approximately 557,000 net acres in the undeveloped play area and approximately 125,000 net developed acres held by conventional production and located in the portion of the Arkoma Basin that is primarily within the boundaries of our utility gathering system in Arkansas, which we refer to as the

"Fairway." At December 31, 2004, we had drilled and completed 21 vertical test wells in the Fayetteville Shale. Based on results achieved to date and assuming that the oil and gas price environment remains favorable, we expect to allocate up to $100.2 million of our 2005 E&P capital to our Fayetteville Shale play, which would include drilling up to 160 to 170 wells.

Exploration and Production

In 1943, we commenced a program of exploration for and development of natural gas reserves in Arkansas for supply to our utility customers. In 1971, we initiated an E&P program outside Arkansas, unrelated to the utility's requirements. Since that time, our E&P activities outside Arkansas have expanded substantially. In 1998, we brought in a new executive management team for our E&P business. Our executives have assembled a high-quality team of management and technical professionals with knowledge and experience in the geologic basins in which we have operations, including experienced explorationists with proven track records of finding natural gas and oil. Our E&P business is organized into asset management teams based on the geographic location of our exploration and development projects.



Areas of Operation

We operate our E&P business in four general regions—the Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. Operating income for our E&P business was $164.6 million and EBITDA was $231.8 million in 2004. Our operating income and EBITDA increased in 2004 from $84.7 million and $132.0 million, respectively, in 2003, primarily due to a 31% increase in production volumes and higher realized natural gas and oil prices. Our operating income and EBITDA increased in 2003 from $36.0 million and $83.1 million, respectively, in 2002, primarily due to higher realized natural gas and oil prices and slightly higher production volumes. We refer you to "Business Overview—Other Items—Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a reconciliation of EBITDA with our net income. In addition to our core operations, we actively seek to develop new conventional exploration projects as well as unconventional plays (which we refer to as New Ventures) with significant exploration and exploitation potential.

Our estimated proved natural gas and oil reserves were 645.5 Bcfe as of December 31, 2004, up from 503.1 Bcfe at year-end 2003 and 415.3 Bcfe at year-end 2002. The increase in total reserves over the past three years is primarily due to the accelerated development of our Overton Field in East Texas, our successful conventional drilling program in the Arkoma Basin, and development of a new field in the Permian Basin. Our year-end 2004 reserves had an after-tax PV-10 value, or standardized measure, of $892.3 million, up from $716.4 million at year-end 2003 and $501.6 million at year-end 2002. We refer you to Note 6 in the consolidated financial statements for a discussion of our standardized measure of discounted future cash flows related to our proved natural gas and oil reserves. Approximately 92% of our proved reserves were natural gas and 83% were classified as proved developed. We operate approximately 76% of our reserves, based on our PV-10 value, and our average proved reserves-to-production ratio, or average reserve life, approximated 11.9 years at year-end 2004. Sales of natural gas production accounted for 92% of total operating revenues for this segment in 2004 as compared with 91% in 2003 and 88% in 2002. Natural gas production has increasingly generated a substantial portion of total operating revenues as a result of the natural gas focus of our capital investments in the past three years.

In 2004, we replaced 365% of our production volumes by adding 197.2 Bcfe of proved natural gas and oil reserves at a finding and development cost of $1.43 per Mcfe, including a net downward reserve revision of 12.7 Bcfe. In 2003 and 2002, our reserve replacement ratios were 313% and 215%, respectively, and our finding and development costs were $1.33 per Mcfe and $0.99 per Mcfe, respectively, including a net downward reserve revision of 15.5 Bcfe in 2003 and a net upward reserve revision of 2.5 Bcfe in 2002. The negative reserve revisions during 2004 were primarily due to slightly higher decline rates related to some of the wells in our Overton Field in East Texas, while negative revisions in 2003 were primarily due to poorer-than-expected well performance related to our South Louisiana properties. Revisions during 2002 were positive primarily due to higher year-end commodity prices. The increase in our reserve replacement ratio during this time period is primarily due to increased success of our drilling programs in finding new natural gas and crude oil reserves and an increasing level of capital expenditures. The increase in our finding and development costs primarily reflects the general increase in material costs and oil field service costs to drill and complete wells in our key operating areas, as well as approximately $14.0 million and $11.0 million invested during 2004 and 2003, respectively, in acquiring leasehold positions in our Fayetteville Shale play. For the period ending December 31, 2004, our three-year average reserve replacement ratio was 305%, and our estimated three-year average finding and development cost was $1.30 per Mcfe, including reserve revisions.

Our reserve replacement ratio during 2004, excluding the effect of reserve revisions, was 388%, compared to 351% in 2003 and 209% in 2002. Our finding and development cost, excluding revisions, was $1.34 per Mcfe in 2004, compared to $1.18 per Mcfe in 2003 and $1.02 per Mcfe in 2002. The increase in our finding and development costs during this time period were primarily due to higher costs for drilling and other field services. Excluding reserve revisions, these three-year averages were 324% and $1.23 per Mcfe, respectively.

The following table provides information as of December 31, 2004 related to proved reserves, well count, and net acreage, and 2004 annual information as to production and capital expenditures, for each of our core operating areas, for our New Ventures and overall:

	Arkoma						
	Conventional	**Fayetteville Shale Play**	**East Texas**	**Permian**	**Gulf Coast**	**New Ventures**	**Total**
Estimated Proved Reserves:							
Total Reserves (Bcfe)	239.5	7.5	299.1	60.8	38.6	-	645.5
Percent of Total	37%	1%	47%	9%	6%	-	100%
Percent Natural Gas	100%	100%	96%	45%	84%	-	92%
Percent Proved Developed	81%	47%	83%	90%	93%	-	83%
Production (Bcfe)	20.1	0.1	22.2	7.1	4.6	-	54.1
Capital Investments (millions)	$53.2	$27.9	$156.7	$27.0	$15.7	$1.5	$282.0
Total Gross Wells	890	10	199	388	64	-	1,551
Total Net Acreage	483,223	557,149	31,785	39,047	13,581	47,596	1,172,381
Net Undeveloped Acreage	293,896	552,689	14,850	13,505	2,161	47,596	924,697
PV-10:							
Pre-tax (millions)	$492.8	$9.4	$503.9	$118.0	$94.3	-	$1,218.4
After-tax (millions)	$360.9	$6.9	$369.0	$86.4	$69.1	-	$892.3
Percent of Total	40%	1%	41%	10%	8%	-	100%
Percent Operated	80%	100%	89%	28%	45%	-	76%

Arkoma Basin. We have traditionally operated in a portion of the Arkoma Basin that is primarily within the boundaries of our utility gathering system in Arkansas, which we refer to as the "Fairway." In recent years, we have expanded our activity in the Arkoma Basin south and east of the traditional Fairway area and into the Oklahoma portion of the basin. Our drilling program in the Arkoma Basin is comprised of both conventional and unconventional activities. We refer to our drilling program targeting stratigraphic Atokan-age objectives in Oklahoma and in the Fairway and in the Ranger Anticline area located south of the Fairway in Arkansas as our "conventional Arkoma" drilling program. Our Fayetteville Shale play represents our entire unconventional drilling program in the Arkoma Basin. At December 31, 2004, we had approximately 247.0 Bcf of natural gas reserves in the Arkoma Basin, representing approximately 38% of our total reserves, up from 211.7 Bcf at year-end 2003 and 188.7 Bcf at year-end 2002.

Conventional Arkoma Program. Our conventional Arkoma drilling program continues to provide a solid foundation for our E&P program and represents a significant source of our production and reserves. Approximately 239.5

Bcf of our reserves at year-end 2004 were attributable to our conventional Arkoma wells. During 2004, we participated in 70 wells with 55 producers, 9 dry holes and 6 wells in progress at year-end, resulting in an 86% drilling success rate while adding 43.4 Bcf of gas reserves at a finding and development cost of $1.23 per Mcf, excluding a net upward reserve revision of 4.5 Bcf, or $1.11 per Mcf including such revision. This compares to finding and development costs of $1.14 per Mcf in the basin in 2003 and $0.99 per Mcf in 2002, excluding net upward reserve revisions of 13.1 Bcf and 4.4 Bcf, respectively. Including such revisions, finding and development costs would have been $0.79 per Mcf in 2003 and $0.80 per Mcf in 2002. The increase in our finding costs during this time period was primarily due to higher costs for drilling and other oil field services. Our gas production from our conventional drilling program in the Arkoma Basin was 20.1 Bcf during 2004, or approximately 55 MMcf per day, compared to 18.9 Bcf in 2003 and 19.8 Bcf in 2002. The increase in production in 2004 was primarily due to a greater number of wells drilled in the basin and higher production volumes from our Ranger Anticline area. The decrease in production during 2003 from 2002 levels was primarily due to the natural decline in our properties, offset somewhat by production from new wells drilled in the year.

Our conventional activities in the Arkoma Basin continue to generate a significant amount of our cash flow. With three-year average finding and development costs of $1.15 per Mcf, excluding revisions (or $0.93 per Mcf including revisions), and three-year average production, or lifting, costs of $0.43 per Mcf (including production taxes), our cash margins from our conventional drilling program in the Arkoma Basin are very attractive. Lifting costs continued to be low during 2004 at $0.48 per Mcf (including production taxes), compared to $0.46 per Mcf in 2003 and $0.30 per Mcf in 2002. While lifting costs from our conventional drilling program in the basin have increased primarily due to higher oil field service costs, we continue to be one of the lowest cost producers in the industry.

Our strategy in the Fairway is to delineate new geologic prospects and extend previously identified trends using our extensive database of regional structural and stratigraphic maps. In 2004, we completed 16 wells out of 19 drilled in the Fairway, adding 2.4 Bcf of new natural gas reserves. The average working interest in our 2004 Fairway wells drilled is 44% and our average net revenue interest is 38%. We intend to drill up to 18 conventional wells and perform at least 29 workovers in the Fairway portion of the Arkoma Basin in 2005.

In recent years, we have extended our development program into the Oklahoma portion of the Arkoma Basin, and into other areas of the basin in Arkansas that have been lightly explored to date. Since 2002, we have significantly increased our drilling activity in our Ranger Anticline prospect area, located at the southern edge of the Arkansas portion of the basin, largely as a result of continued drilling success and favorable regulatory developments. In 2003, Act 964 was passed by the Arkansas legislature providing operators with the opportunity to pursue multi-well development of original 640-acre units. Also during 2003 we received regulatory approval to downspace a large portion of the Ranger Anticline area to 80-acre spacing. In 2004, we obtained further regulatory approval to reduce well spacing from 80-acres per well to a minimum distance of 560 feet between wells at Ranger, which provides more efficient development of the field and greater flexibility to site the wells in the most geologically advantageous locations.

We drilled our first successful well at Ranger in 1997, and through year-end 2004, we successfully drilled 43 out of 50 wells at Ranger, adding 62.8 net Bcf of reserves at a finding cost of $0.72 per Mcf, including reserve revisions. During 2004, we successfully completed 20 out of 22 wells, which added 29.8 Bcf of new reserves at a finding and development cost of $0.82 per Mcf, including revisions. At December 31, 2004, gross production from the field was 23.4 MMcf per day, compared to 7.6 MMcf per day at year-end 2003 and 2.3 MMcf per day at year-end 2002. Our wells at Ranger typically target the Upper and Lower Borum tight gas sands between 5,000 and 8,000 feet in depth. These wells cost approximately $1.0 million to drill and complete, have average initial production rates of approximately 1.8 MMcf per day when successful, and have average estimated ultimate gross reserves of 1.8 Bcf per well. Our average working interest in the 43 successful wells drilled through December 31, 2004 is 81% and our average net revenue interest is 66%.

Our growing understanding of the geology at Ranger indicates that the productive area is larger than originally thought in 1997. In each of the last two years, we increased our acreage position at Ranger and, as of December 31, 2004, we held approximately 7,700 gross developed acres and 43,500 gross undeveloped acres. Our average working interest in our gross undeveloped acreage position at Ranger is 60%. We believe that Ranger holds significant future development potential. In 2005, we intend to drill up to 43 wells in this area and we estimate that there could be over 100 additional locations to drill in 2006 and beyond.

Our strategy for the conventional Arkoma Basin drilling program is to continue our development drilling and workover programs at a level that maintains our production and reserve base. In 2005, we plan to invest approximately $59.3 million in the conventional Arkoma program to drill approximately 86 wells and perform at least 31 workover projects.

Fayetteville Shale Play. In August 2004, we announced that we are testing a new unconventional shale gas play on the Arkansas side of the Arkoma Basin, which we refer to as the Fayetteville Shale play. We are drilling test wells targeting the Fayetteville Shale, an unconventional gas reservoir, ranging in depths from 1,500 to 6,500 feet. The Fayetteville Shale is a Mississippian-age shale that is the geologic equivalent of the Caney Shale found on the Oklahoma side of the Arkoma Basin and the Barnett Shale found in north Texas.

Our Fayetteville Shale play is the outgrowth of extensive internal geologic analysis that began in 2002 when we recognized an incongruity in the amount of gas production that was attributed to completions in the Wedington Sandstone. The Wedington Sandstone is embedded within the Fayetteville Shale sequence. In several incidents within the Fairway area, more gas was being produced than would have been expected based on the Wedington's thickness, petrophysical properties and aerial extent. In 2002, we undertook and completed an extensive geologic study to understand the distribution of the Fayetteville Shale throughout the basin, including its thickness, burial history and thermal maturity. We also obtained Fayetteville Shale core samples associated with the drilling of development wells in our conventional Fairway drilling program. The samples were analyzed for the critical shale properties necessary for successful shale gas plays. The analyses indicated encouraging data relative to total organic content, which ranged from 4.0% to 9.5%, thermal maturity, which ranged from 1.5 to 4.0 and total gas content, which ranged from 60 to 220 standard cubic feet, or scf, per ton, which compared favorably to other productive shale gas plays, including the Barnett. The analyses, along with an extensive geologic mapping project, led us to believe that the Fayetteville Shale represented a legitimate objective reservoir and in early 2003 we commenced acquiring a land position. By December 31, 2003, we had acquired 343,351 net undeveloped acres in the play area, which we disclosed as "New Ventures" acreage in our 2003 annual report on Form 10-K. In June 2004, we initiated a pilot well drilling program in the Fayetteville Shale and 21 vertical wells had been drilled as of December 31, 2004. The test wells were drilled in five pilot areas located in Franklin, Conway, Van Buren and Faulkner counties in Arkansas. The Fayetteville Shale was present as predicted by prior mapping across the tested area and appears to be laterally extensive, ranging in thickness from 50 to 325 feet. At December 31, 2004, ten wells had been placed on production and were producing at rates ranging from 100 to 500 Mcf per day, with the longest production history of approximately 150 days. Of the remaining wells drilled, six were in various stages of testing or completion, two were awaiting pipeline connection with production test rates prior to shut-in of 325 and 1,320 Mcf per day, and three were shut-in as they appear to be marginal performers. Of the 21 wells drilled through December 31, 2004, 19 wells were completed using nitrogen foam fracture stimulation treatments of various sizes, and two wells were completed with slick-water fracture treatments. We have seen significant variability in well performance, and will continue to pursue optimization of our fracture stimulation treatments to maximize well performance.

In 2004, we invested approximately $27.9 million in our Fayetteville Shale play, which included $11.6 million in capital for drilling 21 wells, $14.0 million for leasehold acquisition, and $2.3 million for other capitalized costs. We increased our leasehold position to 557,149 net acres in the undeveloped play area at December 31, 2004. In addition, we control approximately 125,000 net developed acres in our traditional "Fairway" area of the basin that is held by conventional production. Total proved gas reserves booked in the play in 2004 totaled 7.5 Bcf from a total of 20 wells, 10 of which were classified as proved, undeveloped locations, for an average estimated ultimate recovery per well of 430,000 Mcf (375,000 Mcf net).

Based on results achieved to date and assuming that the current oil and gas price environment continues to be favorable, we expect to allocate up to $100.2 million of our 2005 E&P capital to our unconventional Fayetteville Shale play, which would include drilling up to approximately 160 to 170 wells. Our drilling program with respect to our Fayetteville Shale play is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation, the extent to which we can replicate the results of our most successful Fayetteville Shale wells on our other Fayetteville Shale acreage as well as the gas and oil commodity price environment. We refer you to "Risk Factors—Our drilling plans for the Fayetteville Shale play are subject to change." As previously noted, as of December 31, 2004, we had only drilled 21 wells in areas that represent a very small sample of our large acreage position. We continue to gather data about our prospects in the Fayetteville Shale, and it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all.

East Texas. Our East Texas operations are primarily located in the Overton Field in Smith County, Texas, which produces from four Taylor series sands in the Cotton Valley formation at approximately 12,000 feet. Overton provides a low-risk, multi-year drilling program with significant production and reserve growth potential based on the potential level of infill drilling. Our original interest in the Overton Field (which was approximately 10,800 gross acres) was acquired in April 2000 for $6.1 million. Our interest now totals approximately 24,400 gross acres, our average working interest in the Overton Field is 96% and average net revenue interest is 77%.

When we acquired the field in April 2000, it was primarily developed on 640-acre spacing, or one well per square mile. Analogous Cotton Valley fields in the area have been drilled to 80-acre spacing, and in some cases to 40-acre spacing. In 2003, we received regulatory approval from the Texas Railroad Commission to allow downspacing at Overton to optional 80-acre spacing. We also received approval in 2003 to drill four wells at locations that were effectively 40-acre spaced wells. Of the four test wells drilled at 40-acre spacing, three wells indicated pressures near original reservoir pressures and one showed partial depletion. Data from the four 40-acre spaced wells indicated that a significant portion of the field would likely require 40-acre spaced wells to adequately develop the field. During the first quarter of 2004, we received regulatory approval to allow downspacing at Overton to optional 40-acre spacing.

In 2004, we drilled and completed a total of 83 wells, of which 35 were 40-acre spaced wells. This compares to 57 wells drilled and completed in 2003 and 18 wells in 2002. We have experienced a 100% success rate at Overton since we began our development drilling program in 2001. Daily gross production at the Overton Field has increased from approximately 2.0 MMcfe in March 2001 to approximately 90.0 MMcfe at year-end 2004 resulting in net production of 21.8 Bcfe during 2004, compared to 13.6 Bcfe in 2003 and 5.9 Bcfe in 2002. New wells drilled in the field during 2004 averaged approximately $1.6 million to drill and complete, had average initial production rates of approximately 2.9 MMcfe per day and had average estimated ultimate gross reserves of 2.0 Bcfe per well. Our average production costs (including production taxes) were $0.50 per Mcfe in 2004, compared to $0.45 per Mcfe in 2003 and $0.40 per Mcfe in 2002. The increases in our unit production costs were primarily due to higher production taxes resulting from higher realized commodity prices, partially offset by increased production.

Our proved reserves in East Texas increased to 299.1 Bcfe at year-end 2004, or 47% of our total reserves, of which 296.6 Bcfe of reserves were in our Overton Field. Our reserves at Overton were up significantly from 196.3 Bcfe at year-end 2003 and 111.0 Bcfe at year-end 2002, primarily due to the acceleration of our infill drilling program in early 2003. We invested approximately $148.0 million at the Overton Field during 2004 which resulted in proved reserve additions of 142.2 Bcfe at a finding and development cost of $1.04 per Mcfe, excluding a net downward reserve revision of 19.2 Bcfe, or $1.20 per Mcfe including such revision. Our finding and development costs were $0.95 per Mcfe excluding a net downward reserve revision of 3.7 Bcfe (or $0.98 per Mcfe including such revision) in 2003 and $0.60 per Mcfe excluding a net upward reserve revision of 2.8 Bcfe (or $0.57 per Mcfe including such revision) in 2002. The average estimated ultimate recovery of gas and oil reserves from new wells completed in 2004 was approximately 2.0 gross Bcfe per well, compared to 2.2 gross Bcfe per well in 2003 and 2.9 gross Bcfe per well in 2002. The decrease in gross reserves per well over this time period is primarily due to our drilling of locations with the highest anticipated ultimate recovery earlier in our development program and we expect that this trend will continue with future development wells in the field. Our finding cost increased in 2004 primarily due to slightly lower reserves per well combined with higher costs for drilling and other oil field services. Our finding cost in 2003 increased primarily due to the installation of additional field production facilities and the acquisition of producing properties for future development.

In 2005, we plan to invest approximately $147.6 million in East Texas and drill approximately 96 wells, of which approximately 80 wells are planned at Overton. Based on reasonable gas price assumptions and our investment hurdle rate, it appears that our drilling program at Overton could be extended through 2006. With a NYMEX gas price of $5.00 per Mcf, we estimate that approximately 37 wells could be drilled beyond our 2005 drilling program. Alternatively, with a NYMEX gas price of $6.00 per Mcf, we estimate that approximately 92 wells could be drilled beyond our 2005 drilling program.

Permian Basin. We have had an active drilling program since 1997 in the Permian Basin, which is primarily located in west Texas and southeast New Mexico. In July 2004, we acquired additional working interest in our River Ridge field for $14.2 million, which consolidated our position in this property and allowed us to gain additional development opportunities. The acquisition increased our working interest in an existing producing well to 50% from 12.5%, and gave us a 50% working interest in another well in which we previously held no interest. The acquired interest added approximately 5.8 net Bcfe in proved reserves. We subsequently participated in drilling three additional wells in the field, bringing the well count to five, and all were producers. Net production from the field during 2004 was 3.2 Bcfe and total net proved reserves as of December 31, 2004, were approximately 11.0 Bcfe, bringing our overall finding and development cost in the field to $1.63 per Mcfe, excluding reserve revisions (or $1.64 per Mcfe including negative reserve revisions of 0.1 Bcfe). We hold a 50% working interest in this field.

At December 31, 2004, our proved reserves in the Permian Basin were 60.8 Bcfe, compared to 55.6 Bcfe in 2003 and 57.1 Bcfe in 2002. Our production in the basin during 2004 was 7.1 Bcfe, or approximately 19 MMcfe per day, compared to 4.2 Bcfe in 2003 and 4.9 Bcfe in 2002. The increase in reserves and production from 2003 was primarily due to increased volumes from our River Ridge discovery and subsequent development of that field during 2004. Our production costs (including production taxes) averaged $1.21 per Mcfe, compared to $1.15 per Mcfe in 2003 and $1.13 per

Mcfe in 2002. The increases in production costs were primarily due to increased production taxes resulting from higher gas and oil commodity prices. Our finding and development cost in the Permian in 2004 was $2.62 per Mcfe excluding a net upward reserve revision of 2.6 Bcfe, or $2.09 per Mcfe including such revision. Our finding and development costs were $0.95 per Mcfe excluding a net downward reserve revision of 7.1 Bcfe (or $3.44 per Mcfe including such revision) in 2003 and $3.57 per Mcfe excluding a net downward reserve revision of 0.1 Bcfe (or $3.85 per Mcfe including such revision) in 2002. The increase in finding cost in 2004, excluding revisions, was primarily due to the acquisition of additional working interest in our River Ridge discovery while the decrease in finding cost during 2003 was primarily due to the initial discovery itself.

In 2004, we invested $27.0 million, drilling 14 wells, of which 8 were successful, resulting in reserve additions of 10.3 Bcfe. In 2005, we plan to invest approximately $4.8 million in our Permian Basin program to drill approximately 12 exploration and exploitation wells.

Gulf Coast. Our Gulf Coast operations are located in the onshore areas of Texas and Louisiana. Since our first discovery in December 1999, the efforts of our exploration program have resulted in 10 successful wells out of 23 wildcats drilled in South Louisiana. We have not had a significant discovery in South Louisiana since 2001. In 2002 and 2003, we participated in 12 wells, 3 of which were successful. In 2004, we participated in two exploration wells in South Louisiana, one of which was successful. We own a 50% working interest in the successful well. Our proved reserves in these areas totaled 38.6 Bcfe at December 31, 2004, compared to 39.5 Bcfe at year-end 2003 and 58.5 Bcfe at year-end 2002. Approximately 14.2 Bcfe of reserves at December 31, 2004, were located in Louisiana. The decline in reserves during 2004 was primarily due to the natural decline in these properties, partially offset by 4.3 Bcfe of reserve adds from drilling. In 2003, we revised our reported reserve estimates for this area downward by 17.7 Bcfe primarily due to poorer-than-expected well performance related to our South Louisiana properties. Net production from this area in 2004 was 4.6 Bcfe, or approximately 13 MMcfe per day, compared to 4.5 Bcfe in 2003 and 7.5 Bcfe in 2002. The decrease in production in 2003 from 2002 was primarily due to poorer-than-expected well performance related to our South Louisiana properties. Production costs (including production taxes) averaged $1.39 per Mcfe during 2004, compared to $1.23 per Mcfe in 2003 and $1.07 per Mcfe in 2002. The increase in our unit production costs over this time period was primarily due to the decline in production volumes from these properties. In 2004, our finding and development cost was $3.65 per Mcfe, excluding reserve revisions, compared to $6.00 per Mcfe in 2003 and $3.68 per Mcfe in 2002. The relatively high finding costs during this time period was primarily due to the lack of significant success in our South Louisiana exploration program over the last three years.

In 2004, we invested $15.7 million in this area, adding 4.3 Bcfe of reserves. Our recent drilling activities in this area are not meeting our economic criteria and we are reducing our investments in the Gulf Coast to $4.8 million in 2005. While we still plan to drill up to 8 wells in the area in 2005, the majority of these wells will be developmental in nature.

Other Exploration and New Ventures. In addition to our core operations, we actively seek to develop new conventional exploration projects as well as unconventional plays (which we refer to as New Ventures) with significant exploration and exploitation potential. We have personnel dedicated to the research and identification of active and potential plays, focusing on both conventional exploration plays and unconventional plays (including coal bed methane, shale gas and basin-centered gas) as well as the technological aspects such as horizontal drilling and fracture techniques. New prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria. As of December 31, 2003, we had acquired 345,310 net undeveloped leasehold acres in new project areas for approximately $11.0 million, which we disclosed as “New Ventures” acreage in our 2003 annual report on Form 10-K. Of these 345,310 net undeveloped acres, approximately 343,351 acres related to our Fayetteville Shale play in Arkansas, which is now part of our Arkoma operations. In early 2004, we acquired 95,000 net acres in a coal bed methane play located in the Crazy Mountain Basin in Montana and drilled a test well to determine its producibility. We determined that the coal resource was too thin to be commercially developed and are not pursuing this coal bed methane play any further. During 2004, we also acquired approximately 47,596 acres in areas of the United States outside of our core operating areas in connection with other unconventional natural gas and oil plays that we are pursuing.

In 2004, we invested approximately $1.5 million in New Ventures, excluding the Fayetteville Shale play, which included drilling one exploration well relating to the abandoned coal bed methane play. In 2005, we plan to invest approximately $18.1 million in exploration projects and $4.2 million in New Venture projects, including drilling up to 14 exploration and unconventional wells in the continental United States.

Acquisitions and Divestitures

In 2004, we purchased 5.8 Bcfe of proved reserves for $14.2 million at an average cost of $2.45 per Mcfe. Almost all of this investment related to the acquisition of additional working interest in our River Ridge discovery in Lea County, New Mexico.

In 2003, we purchased an aggregate of 1.1 Bcfe of proved reserves for $3.0 million, at an average cost of $2.73 per Mcfe. The transactions included working interests in our core Arkoma Basin, Overton Field and Permian Basin producing areas. The average cost per Mcfe was higher than for prior acquisitions due to the potential existence of future drilling opportunities beyond the existing production.

In 2002, we purchased 6.6 Bcfe of proved reserves for $3.1 million, at an average cost of $0.47 per Mcfe. The largest single transaction was the acquisition of a minority interest in the Susser #2 well located in Nueces County, Texas for $1.7 million. We are the operator of the well. The remaining $1.2 million was spent to acquire additional working interests in the Overton Field and in several Arkoma Basin wells.

In November 2002, we sold our remaining non-strategic Mid-Continent properties, including our properties in the Sho-Vel-Tum area in southern Oklahoma, the Anadarko Basin in western Oklahoma and the Sooner Trend in northwestern Oklahoma, for a total of $26.4 million. These properties represented approximately 32.9 Bcfe of reserves and produced approximately 2.5 Bcfe annually.

As part of our business strategy, we selectively review opportunities to acquire producing properties and leasehold acreage, focusing in particular on the regions where we have existing operations, operational control of properties and significant unrealized exploitation and exploration potential.

Capital Expenditures

We invested a total of $282.0 million in our E&P program and participated in drilling 204 wells during 2004. Of these drilled wells, 166 were successful, 14 were dry and 24 were still in progress at year-end. Our investments were balanced between our core areas of operations, with approximately $53.2 million invested in our conventional Arkoma Basin drilling program, $156.7 million in East Texas, $27.0 million in the Permian Basin, and $15.7 million in the Gulf Coast. In addition, we invested approximately $27.9 million in our Fayetteville Shale play and $1.5 million in our New Ventures. Of the $282.0 million invested, approximately $20.1 million was invested in exploratory drilling, $208.7 million in development drilling and workovers, $21.1 million for leasehold acquisition and seismic expenditures, $14.2 million for producing property acquisitions, and $17.9 million in capitalized interest and expenses and other technology-related expenditures. During 2003, we invested a total of $170.9 million in our E&P business and participated in 139 wells, and in 2002 we invested $85.2 million and participated in 65 wells. The increases in capital investments and wells drilled during this time was primarily due to the acceleration of our development drilling program at our Overton Field, an increase in conventional drilling activity at our Ranger Anticline area in the Arkoma Basin, and leasehold investments and drilling in our Fayetteville Shale play.

In 2005, we intend to allocate up to $339.0 million for our E&P capital budget, an increase of approximately 20% over our capital investment level in 2004. We continue to be focused on our strategy of adding value through the drillbit, as over 80% of our 2005 E&P capital is allocated to drilling. Our investments in 2005 will primarily be focused on our lower-risk, high-return conventional drilling programs in East Texas and the Arkoma Basin. During 2005, we expect to invest approximately $147.6 million in East Texas and $59.3 million in our conventional Arkoma Basin drilling program. Based on results achieved to date and assuming that the oil and gas price environment continues to be favorable, we also expect to allocate up to $100.2 million of our 2005 E&P capital to our unconventional Fayetteville Shale play. The remainder of our E&P capital will be allocated to exploration and exploitation in the Permian Basin ($4.8 million), the onshore Gulf Coast ($4.8 million) and to other exploration projects ($18.1 million) and New Venture projects ($4.2 million). Of the up to $339.0 million allocated to the E&P capital budget, approximately $256.6 million will be invested in development drilling, $24.5 million in exploratory drilling, $26.8 million for land and seismic, $24.0 million in capitalized interest and expenses and $7.1 million in equipment, facilities and technology-related expenditures. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Expenditures" for a discussion of our planned capital expenditures in 2005.

Other Revenues

Other revenues and operating income for 2004 and 2003 also included pre-tax gains of $4.5 million and $3.1 million, respectively, related to the sale of gas-in-storage inventory. This compares to virtually no revenue or operating income in 2002 from the sale of gas-in-storage inventory.

Sales and Major Customers

Our daily natural gas equivalent production averaged 148.2 MMcfe in 2004, up 31% from 112.7 MMcfe in 2003. Our daily natural gas equivalent production was 109.8 MMcfe in 2002. Our natural gas production was 50.4 Bcf in 2004, compared to 38.0 Bcf in 2003 and 36.0 Bcf in 2002. We also produced 618,000 barrels of oil in 2004, compared to 531,000 barrels of oil in 2003 and 682,000 barrels in 2002. Our gas production has increased since 2002 primarily due to the acceleration of our development drilling program at our Overton Field in East Texas, which predominantly produces gas. Our oil production increased in 2004 due to increased oil production from our River Ridge discovery. Our oil production declined in 2003 due to the sale of our Mid-Continent properties in November 2002, which were predominantly oil producing properties. For 2005, we are targeting our total natural gas and crude oil production to be approximately 61.0 Bcfe to 63.0 Bcfe, which equates to a growth rate of approximately 13% to 17% above our 2004 production volumes.

We realized an average wellhead price of $5.21 per Mcf for our natural gas production in 2004, compared to $4.20 per Mcf in 2003 and $3.00 per Mcf in 2002, including the effect of hedges. Our hedging activities lowered our average gas price $0.59 per Mcf in 2004, $0.95 per Mcf in 2003, and $0.11 per Mcf in 2002. Our average oil price realized was $31.47 per barrel in 2004, compared to $26.72 per barrel in 2003 and $21.02 per barrel in 2002, including the effect of hedges. Our hedging activities lowered our average oil price $9.08 per barrel in 2004, $2.94 per barrel in 2003 and $2.92 per barrel in 2002.

Our gas sales to unaffiliated purchasers were 45.0 Bcf in 2004, compared to 32.1 Bcf in 2003 and 30.6 Bcf in 2002. Gas sales volumes to our affiliated utility subsidiary, Arkansas Western, have been fairly stable over the past three years, averaging approximately 5.5 Bcf annually. All of our oil production is sold to unaffiliated purchasers. This gas and oil production is sold under contracts that reflect current short-term prices and which are subject to seasonal price swings. These combined gas and oil sales to unaffiliated purchasers accounted for 82% of total E&P revenues in 2004, 86% in 2003 and 85% in 2002. In 2004, the largest unaffiliated purchaser accounted for 9% of total E&P revenues.

Our utility subsidiary, Arkansas Western is the largest single customer for sales of our gas production. These sales are made by SEECO primarily under contracts obtained under a competitive bidding process. We refer you to "Natural Gas Distribution—Gas Purchases and Supply" below for further discussion of these contracts. Sales to Arkansas Western accounted for approximately 10% of total E&P revenues in 2004, 12% in 2003 and 15% in 2002. SEECO's sales to Arkansas Western were 5.5 Bcf in 2004, compared to 5.9 Bcf in 2003 and 5.4 Bcf in 2002. Sales to Arkansas Western are primarily driven by the utility's changing supply requirements due to variations in the weather and SEECO's ability to obtain gas supply contracts that are periodically placed out for bids. SEECO's gas production provided approximately 40% of the utility's requirements in 2004, 41% in 2003 and 37% in 2002. We also sell gas directly to industrial and commercial transportation customers located on Arkansas Western's gas distribution systems. SEECO also owns an unregulated natural gas storage facility that has historically been utilized to help meet its peak seasonal sales commitments. The storage facility is connected to Arkansas Western's distribution system.

Future sales to Arkansas Western's gas distribution systems will be dependent upon our success in obtaining gas supply contracts with the utility systems. In the future, our subsidiaries will continue to bid to obtain these gas supply contracts, although there is no assurance that they will be successful. If successful, we cannot predict the amount of fixed demand charges, if any, that would be associated with the new contracts. We expect future increases in our gas production to come primarily from sales to unaffiliated purchasers. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand of both affiliated and unaffiliated customers for our production.

We periodically enter into hedging activities with respect to a portion of our projected natural gas and crude oil production through a variety of financial arrangements intended to support natural gas and oil prices at targeted levels and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2004, we had hedges in place on 44.6 Bcf of 2005 gas production, 27.0 Bcf of 2006 gas production, 360,000 barrels of 2005 oil production and 120,000 barrels of 2006 oil production. Subsequent to December 31, 2004 and prior to March 3, 2005, we hedged 4.0 Bcf of 2006 gas production under costless collars with floor prices of $5.50 per Mcf and ceiling prices ranging from $7.60 to $13.50 per Mcf. As of

December 31, 2004, we had hedges in place on approximately 70% to 80% of our targeted 2005 gas production and approximately 60% to 70% of our 2005 targeted oil production. We refer you to Item 7A of this Form 10-K, "Quantitative and Qualitative Disclosures About Market Risk," for further information regarding our hedge position at December 31, 2004.

Disregarding the impact of hedges, based on the current price environment, we expect the average price received for our gas production to be approximately $0.30 to $0.50 per Mcf lower than average spot market prices, as market differentials that reduce the average prices received are partially offset by demand charges under the contracts covering our intersegment sales to Arkansas Western. Disregarding the impact of hedges, based on the current price environment, we expect the average price received for our oil production to be approximately $1.25 per barrel lower than average spot market prices, as market differentials reduce the average prices received.

Competition

All phases of the oil and gas industry are highly competitive. We compete for properties, reserves, and the labor and equipment required to conduct our operations. Our competitors include major oil and gas companies, other independent oil and gas companies and individual producers and operators. Many of these competitors have financial and other resources that substantially exceed those available to us.

Competition has increased in recent years due largely to the development of improved access to interstate pipelines. Due to our significant leasehold acreage position in Arkansas and our long-time presence and reputation in this area, we believe we will continue to be successful in acquiring new leases in Arkansas. While improved intrastate and interstate pipeline transportation in Arkansas should increase our access to markets for our gas production, these markets will generally be served by a number of other suppliers. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. Outside Arkansas, we are less established and face competition from a larger number of other producers.

Oil Price Controls and Transportation Rates

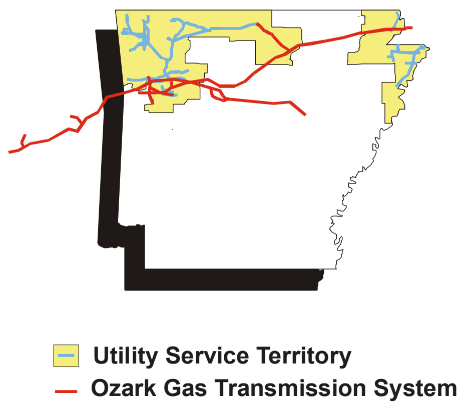
Sales of crude oil, condensate and gas liquids are not regulated and are made at negotiated prices. Effective January 1, 1995, the Federal Energy Regulatory Commission, or the FERC, implemented regulations establishing an indexing system for transportation rates for oil that allowed for an increase in the cost of transporting oil to the purchaser. The implementation of these regulations has not had a material adverse effect on our results of operations.

Federal Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, or the NGA, the Natural Gas Policy Act of 1978, or the NGPA, and regulations promulgated thereunder by the FERC. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, or the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993 and sales by producers of natural gas can be made at uncontrolled market prices. With respect to transportation, commencing in 1992, the FERC issued Order No. 636 and subsequent orders (collectively, "Order No. 636"), which require interstate pipelines to provide transportation separate, or "unbundled," from the pipelines' sales of gas. Order No. 636 also requires pipelines to provide open-access transportation on a basis that is equal for all shippers. Although Order No. 636 does not directly regulate our activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. In 2000, the FERC issued Order No. 637 and subsequent orders (collectively, "Order No. 637"), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. The implementation of these orders has not had a material adverse effect on our results of operations to date. We cannot predict whether and to what extent FERC's market reforms will survive judicial review and, if so, whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that we will be disproportionately as compared to other natural gas producers and marketers affected by any action taken. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated; therefore, there can be no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Natural Gas Distribution

We distribute natural gas to approximately 145,000 customers in northern Arkansas through our subsidiary, Arkansas Western Gas Company. Our utility is focused on capitalizing on the expanding economy and growth in its Northwest Arkansas service territory where approximately 66% of Arkansas Western's customers are located. In 2001, the Fayetteville-Springdale-Rogers MSA was named by the U.S. Census Bureau as the 6th fastest growing MSA in the United States. In November 2004, the Milken Institute named Northwest Arkansas as the 7th "Best Performing City" in the United States, based upon job creation and local economic growth, attributable in part to the presence of Wal-Mart Stores, Inc., the largest public corporation in the world, and other large corporations such as Tyson Foods and J.B. Hunt Transportation.



Operating income for our natural gas distribution business was $8.5 million in 2004, compared to $6.8 million in 2003 and $7.6 million in 2002. EBITDA generated by our utility segment was $15.6 million in 2004, compared to $13.3 million in 2003 and $14.0 million in 2002. We refer you to "Business Overview—Other Items—Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our net income as derived from our audited financial information. In 2004, our analysis indicated that current revenues in our utility segment were not sufficient to cover the cost of providing utility service and earn the rate of return authorized by the APSC. In December 2004, we filed a request with the Arkansas Public Service Commission, or the APSC, for an adjustment in the utility's rates totaling $9.7 million, or 5.2%, annually. The APSC has ten months to review the filing and reach a decision on the amount of the increase to be approved. Any rate increase allowed would likely be implemented in the fourth quarter of 2005.

In September 2003, we received regulatory approval for a rate increase totaling $4.1 million annually, and were allowed to recover certain additional costs totaling $2.3 million over a two-year period. Operating income and EBITDA for 2003 include a gain of $1.0 million related to the recovery of these costs. The rate increase was effective on October 1, 2003. Prior to this, Arkansas Western had not had a rate increase since 1996.

Gas Purchases and Supply

Arkansas Western purchases its system gas supply through a competitive bidding process implemented in October 1998, and directly at the wellhead under long-term contracts with flexible pricing provisions. In 2004, SEECO successfully bid on gas supply packages representing approximately 55% of the requirements for Arkansas Western for 2005 and 2004, compared to approximately 67% for 2003. The decrease in 2005 and 2004 compared to 2003 was primarily due to more favorable bid pricing on gas supply packages from third-party suppliers.

Arkansas Western also purchases gas under its gas supply packages from unaffiliated suppliers accessed by interstate pipelines. These purchases are under firm contracts with one-year to two-year terms. The rates charged by most suppliers include demand components to ensure availability of gas supply and a commodity component that is based on monthly indexed market prices. The pipeline transportation rates include demand charges to reserve pipeline capacity and commodity charges based on volumes transported. Less than 4% of the utility's gas purchases are under take-or-pay contracts. Arkansas Western believes that it does not have a significant exposure to take-or-pay liabilities resulting from these contracts and expects to be able to continue to satisfactorily manage these contracts.

Arkansas Western has a regulated natural gas storage facility connected to its distribution system in Northwest Arkansas that it utilizes to help meet its peak seasonal demands. The utility also owns a liquefied natural gas facility and contracts with an interstate pipeline for additional storage capacity to serve its system in the northeastern part of the state. These contracts involve demand charges based on the maximum deliverability, capacity charges based on the maximum storage quantity, and charges for the quantities injected and withdrawn.

The utility's rate schedules include a cost of gas rider whereby the actual cost of purchased gas above or below the projected level included in the rates is permitted to be billed or is required to be credited to customers. The difference between actual costs of purchased gas and gas costs recovered from customers is deferred each month and is billed or credited, as appropriate, to customers in subsequent months.

Markets and Customers

Arkansas Western provides natural gas to approximately 128,000 residential, 17,000 commercial, and 175 industrial customers, while also providing gas transportation services to approximately 109 end-use and off-system customers. Total gas throughput in 2004 and 2003 was 25.0 Bcf, compared to 27.3 Bcf in 2002. The lower volumes in 2004 and 2003 were due to fewer volumes being transported off-system, the effects of weather, and customer conservation brought about by high gas prices. Weather in 2004 was 10% warmer than normal and 9% warmer than in 2003. Weather in 2003 was 1% warmer than normal and 1% warmer than the prior year. Weather in 2002 was 2% warmer than normal and 8% colder than the prior year.

Residential and Commercial. Approximately 89% of the utility's revenues in 2004 were from residential and commercial markets. Residential and commercial customers combined accounted for 57% of total gas throughput for the gas distribution segment in 2004, compared to 60% in 2003 and 56% in 2002. Gas volumes sold to residential customers were 8.5 Bcf in 2004, compared to 9.0 Bcf in 2003 and 2002. Gas sold to commercial customers totaled 5.7 Bcf in 2004, 6.1 Bcf in 2003 and 6.2 Bcf in 2002. The fluctuations in gas volumes sold to both residential and commercial customers were driven primarily by variations in the weather and customer conservation. The gas heating load is one of the most significant uses of natural gas and is sensitive to outside temperatures. Sales, therefore, vary throughout the year. Profits, however, have become less sensitive to fluctuations in temperature as tariffs implemented contain a weather normalization clause to lessen the impact of revenue increases and decreases that might result from weather variations during the winter heating season.

Industrial and End-use Transportation. Deliveries to Arkansas Western's industrial and end-use transportation customers were 9.8 Bcf in 2004, 9.6 Bcf in 2003 and 9.9 Bcf in 2002. No industrial customer accounts for more than 9% of Arkansas Western's total throughput. Arkansas Western offers a transportation service that allows larger business customers to obtain their own gas supplies directly from other suppliers. Off-system transportation volumes were 1.0 Bcf in 2004, 0.3 Bcf in 2003 and 2.2 Bcf in 2002. The level of off-system deliveries each year generally reflects the changes of on-system demands of our gas distribution systems for our gas production. As of December 31, 2004, a total of 109 customers used the transportation service.

Competition

Arkansas Western has historically maintained a price advantage over alternative fuels such as electricity, fuel oil, and propane for most applications, enabling it to achieve excellent market penetration levels. However, Arkansas Western has experienced a general trend in recent years toward lower rates of usage among its customers, largely as a result of conservation efforts, as well as increasing competition from alternative fuels that has eroded its price advantage. Arkansas Western also has the ability to enter into special contracts with larger commercial and industrial customers that contain lower pricing provisions than the approved tariffs. These contracts can be used to meet competition from alternate fuels or threats of bypass and must be approved by the APSC.

Regulation

Arkansas Western's utility rates and operations are regulated by the APSC and it operates through municipal franchises that are perpetual by virtue of state law. These franchises, however, may not be exclusive within a geographic area. As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation are required to unbundle residential sales services from transportation services in an effort to promote greater competition. Although no such legislation or regulatory directives related to natural gas are presently pending in Arkansas, Arkansas Western is actively controlling costs and constantly reviewing issues such as system capacity and reliability, obligation to serve, rate design and stranded or transition costs.

In Arkansas, legislation was adopted in 2001 for the deregulation of the retail sale of electricity between October 2003 and October 2005. In December 2001, the APSC submitted to the legislature its annual report on the development of electric deregulation and recommended that the legislature consider suspending deregulation until 2010 or 2012. In 2003, the legislation requiring deregulation of the retail sale of electricity was repealed. During 2004, the APSC conducted collaborative meetings to study the feasibility of a large-user access program for electric service choice. On September 30, 2004, the APSC issued a report to the legislature stating that it would not be feasible to implement a large-user access program without shifting costs to other customer classes and recommended that no changes be made to the statutes which would affect access to competitive power supply by large users. To date, the legislature has not taken any action in response to this report. Although Arkansas Western already provides transportation service for its large users, any developments regarding large-user access programs for electricity could set regulatory precedents that would also affect natural gas utilities in the future. These effects may include protection of other customer classes against cost shifting and the regulatory treatment of stranded costs.

In December 2004, Arkansas Western filed a request with the APSC for an adjustment in the utility's rates totaling $9.7 million, or 5.2%, annually. The APSC has ten months to review the filing and reach a decision on the amount of the increase to be approved. Any rate increase allowed would likely be implemented in the fourth quarter of 2005.

In September 2003, Arkansas Western received regulatory approval of a rate increase totaling $4.1 million annually, exclusive of costs to be recovered through its cost of gas rider. The order issued by the APSC also entitled Arkansas Western to recover certain additional costs totaling $2.3 million through its purchased gas adjustment clause over a two-year period. The rate increase was effective for all customer bills rendered on or after October 1, 2003.

In February 2001, the APSC approved a 90-day temporary tariff to collect additional gas costs not yet billed to customers through the normal purchased gas adjustment clause in the utility's approved tariffs. Arkansas Western had under-recovered purchased gas costs of $12.9 million in its current assets at December 31, 2000. The amount of under-recovered purchased gas costs increased significantly during January 2001 as a result of rapidly increasing gas costs. The temporary tariff allowed the utility accelerated recovery of the gas costs it had incurred during the 2000–2001 winter heating season. In April 2002, Arkansas Western filed a revised purchased gas adjustment clause that provides better matching between the time the gas costs are incurred and the time the costs are recovered. The APSC approved the new clause in May 2002. At December 31, 2004, Arkansas Western had over-recovered purchased gas costs of $1.4 million, compared to under-recovered purchase gas costs of $1.1 million in 2003 and over-recovered purchase gas costs of $5.7 million in 2002.

Gas distribution revenues in future years will be impacted by customer growth, customer usage and rate increases allowed by the APSC. We refer you to "Risk Factors—We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future" for a discussion of the impact that government regulation has on our natural gas distribution business.

Marketing, Transportation and Other

Gas Marketing

Our gas marketing subsidiary, Southwestern Energy Services Company, was formed in 1996 to better enable us to capture downstream opportunities which arise through marketing and transportation activity. Our current marketing operations primarily relate to the marketing of our own gas production and some third-party natural gas that is primarily sold to industrial customers connected to our gas distribution systems. Our operating income from marketing was $3.2 million on revenues of $315.0 million in 2004, compared to $2.6 million on revenues of $202.0 million in 2003, and $2.7 million on revenues of $131.1 million in 2002. We marketed 57.0 Bcf of natural gas in 2004, compared to 42.7 Bcf in 2003 and 45.5 Bcf in 2002. The increase in revenues is largely attributable to increased volumes marketed and higher purchased gas costs, while operating income fluctuates depending on the margin we are able to generate between the purchase of the commodity and the ultimate disposition of the commodity. In late 2000, we began marketing less third-party natural gas in an effort to reduce our potential credit risk and concentrated more on marketing our affiliated production. Of the total volumes marketed, purchases from our E&P subsidiaries accounted for 77% in 2004, 75% in 2003 and 67% in 2002. Our E&P subsidiaries have accounted for an increasing percentage of our total volumes marketed because of a shift in our focus to marketing our own production in order to reduce our credit risk.

Transportation

We hold a 25% interest in NOARK, a partnership that owns a 723-mile integrated interstate pipeline system with a total throughput capacity of 330.0 MMcf per day, known as Ozark Gas Transmission System, which became operational November 1, 1998. The remaining 75% interest in the NOARK partnership is owned by Enogex Inc., a subsidiary of OGE Energy Corp.

Deliveries are made by the pipeline to portions of Arkansas Western's distribution systems and to the interstate pipelines with which it interconnects. The average daily throughput for the pipeline was 155.0 MMcf per day in 2004, compared to 115.0 MMcf per day in 2003 and 168.1 MMcf per day in 2002. The average daily throughput decreased in 2003 due primarily to a temporary curtailment by one of the interstate pipelines that connects with Ozark Gas Transmission System.

In 2004, Arkansas Western renegotiated a new ten-year transportation contract with Ozark Gas Transmission System for 66.9 MMcf per day of firm capacity. Our share of NOARK's results of operations was a pre-tax loss of $0.4 million in 2004, compared to pre-tax income of $1.1 million in 2003, and a pre-tax loss of $0.3 million in 2002. The pre-tax loss in 2004 was due primarily to a $0.4 negative adjustment from the operator of the pipeline for prior period allocations of income and expenses to the partners. In the first quarter of 2003, NOARK sold a 28-mile portion of its pipeline located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million and our share of the proceeds was $2.5 million, resulting in a pre-tax gain to us of $1.3 million recorded in the first quarter of 2003. In addition to the gain recognized on the sale, the improvements experienced recently in operating results of NOARK result primarily from the ability to collect higher transportation rates on interruptible volumes.

Other Revenues

Our wholly owned subsidiary, A. W. Realty Company, owns an interest in approximately 17 acres of undeveloped real estate at December 31, 2004. A.W. Realty's real estate development activities are concentrated on tracts of land located near our offices in a growing part of Fayetteville, Arkansas. During 2004, we sold 45.5 acres of commercial real estate located in Fayetteville, Arkansas for a pre-tax gain of $5.8 million. During the third quarter of 2003, we sold 18.5 acres of commercial real estate for a pre-tax gain of $1.7 million, and we sold certain fixed assets for a pre-tax gain of $1.3 million. These amounts were reflected in "Gas transportation and other" revenues in our income statement.

Competition

Our gas marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. Other factors affecting competition are cost and availability of alternative fuels, level of consumer demand, and cost of and proximity to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

The Ozark Gas Transmission System competes with one interstate pipeline to obtain gas supplies for transportation to other markets. We believe that the Ozark Gas Transmission System will be able to obtain the additional future gas supplies necessary to compete effectively for the transportation of natural gas to end-users and markets served by the interstate pipelines.

Regulation

The Ozark Gas Transmission System is an interstate pipeline system subject to FERC regulations and FERC-approved tariffs. The FERC has set the maximum transportation rate of Ozark Gas Transmission System at $0.2867 per dekatherm.

Other Items

Reconciliation of Non-GAAP Measures

EBITDA is defined as net income plus interest, income tax expense, depreciation, depletion and amortization. We have included information concerning EBITDA in this Form 10-K because it is used by certain investors as a measure of the ability of a company to service or incur indebtedness and because it is a financial measure commonly used in our industry. EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as a measure of our profitability or liquidity. EBITDA as defined above may not be comparable to similarly titled measures of other companies.

We believe that net income is the financial measure calculated and presented in accordance with generally accepted accounting principles that is most directly comparable to EBITDA as defined. The following table reconciles EBITDA as defined with our net income, as derived from our audited financial information for the years-ended December 31, 2004, 2003 and 2002:

2004	**E&P**	**Natural Gas Distribution**	**Marketing and Other**	**Total**
Net income	$ 96,307	$ 2,617	$ 4,652	$ 103,576
Depreciation, depletion and amortization (1)	68,794	7,080	191	76,065
Net interest expense	11,537	4,461	994	16,992
Provision for income taxes	55,197	1,471	3,110	59,778
EBITDA	$ 231,835	$15,629	$ 8,947	$ 256,411
2003				
Net income	$ 43,713	$ 1,423	$ 3,761	$ 48,897
Depreciation, depletion and amortization (1)	50,922	6,668	172	57,762
Net interest expense	11,911	4,395	1,005	17,311
Provision for income taxes (2)	25,486	767	2,119	28,372
EBITDA	$ 132,032	$13,253	$ 7,057	$ 152,342
2002				
Net income	$ 11,149	$ 2,241	$ 921	$ 14,311
Depreciation, depletion and amortization (1)	48,570	6,581	201	55,352
Net interest expense	16,597	3,868	1,001	21,466
Provision for income taxes	6,744	1,316	648	8,708
EBITDA	$ 83,060	$14,006	$ 2,771	$ 99,837

(1) Depreciation, depletion and amortization includes the amortization of restricted stock issued under our incentive compensation plans.
(2) Provision for income taxes for 2003 includes the tax benefit associated with the cumulative effect of adoption of accounting principle.

Environmental Matters

Our operations are subject to numerous federal, state and local laws and regulations including the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Clean Water Act, the Clean Air Act and similar state legislation. These laws and regulations:

- require permits for drilling wells;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the natural gas and oil industry in general. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this trend will continue in the future.

The Oil Pollution Act, as amended, or the OPA, and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States' waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

CERCLA, also known as the "Superfund law," imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended, or the RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. The RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the Clean Water Act, the RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

The Federal Water Pollution Control Act, as amended, or the FWPCA, imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The FWPCA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the Environmental Protection Agency, or the EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Although the costs to comply with zero discharge mandates under federal or state law may be significant, the entire industry is expected to experience similar costs and we believe that these costs will not have a material adverse impact on our results of operations or financial position. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

Employees

At December 31, 2004, we had 595 total employees, including 347 employed by our natural gas utility, of which 26 are represented under a collective bargaining agreement. We believe that our relationships with our employees are good.

RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. The risk factors described below are not necessarily exhaustive and investors are encouraged to perform their own investigation with respect to us and our business. Investors should also read the other information included in this Form 10-K, including our financial statements and the related notes.

Natural gas and oil prices are volatile. Volatility in natural gas and oil prices can adversely affect our results and the price of our common stock. This volatility also makes valuation of natural gas and oil producing properties difficult and can disrupt markets.

Natural gas and oil prices have historically been, and are likely to continue to be, volatile. The prices for natural gas and oil are subject to wide fluctuation in response to a number of factors, including:

- relatively minor changes in the supply of and demand for natural gas and oil;
- market uncertainty;
- worldwide economic conditions;
- weather conditions;
- import prices;
- political conditions in major oil producing regions, especially the Middle East;
- actions taken by OPEC;
- competition from other sources of energy; and
- economic, political and regulatory developments.

Price volatility makes it difficult to budget and project the return on exploration and development projects involving our natural gas and oil properties and to estimate with precision the value of producing properties that we may own or propose to acquire. In addition, unusually volatile prices often disrupt the market for natural gas and oil properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Our quarterly results of operations may fluctuate significantly as a result of, among other things, variations in natural gas and oil prices and production performance. In recent years, natural gas and oil price volatility has become increasingly severe.

A substantial or extended decline in natural gas and oil prices would have a material adverse affect on us.

A substantial or extended decline in natural gas and oil prices would have a material adverse effect on our financial position, results of operations, access to capital and the quantities of natural gas and oil that may be economically produced. A significant decrease in price levels for an extended period would negatively affect us in several ways including:

- our cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves or increase production;
- certain reserves would no longer be economic to produce, leading to both lower proved reserves and cash flow; and
- access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable.

Consequently, our revenues and profitability would suffer.

Lower natural gas and oil prices may cause us to record ceiling test write-downs.

We use the full cost method of accounting for our natural gas and oil operations. Accordingly, we capitalize the cost to acquire, explore for and develop natural gas and oil properties. Under the full cost accounting rules of the SEC, the capitalized costs of natural gas and oil properties – net of accumulated depreciation, depletion and amortization, and deferred income taxes – may not exceed a "ceiling limit." This is equal to the present value of estimated future net cash flows from proved natural gas and oil reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects.

These rules generally require pricing future natural gas and oil production at the unescalated natural gas and oil prices in effect at the end of each fiscal quarter, including the impact of derivatives qualifying as hedges. They also require a write-down if the ceiling limit is exceeded, even if prices declined for only a short period of time.

If natural gas and oil prices fall significantly, a write-down may occur. Write-downs required by these rules do not impact cash flow from operating activities but do reduce net income and shareholders' equity.

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

We have experienced and expect to continue to experience substantial capital expenditure and working capital needs, particularly as a result of our drilling program. In particular, our planned capital expenditures for 2005 are expected to exceed the net cash generated by our operations by up to $85 million assuming NYMEX commodity prices of $6.00 per Mcf for natural gas and $36.00 per barrel for oil and that we achieve production results consistent with our forecasts. We expect to borrow under our credit facility to fund capital expenditures that are in excess of our net cash flow. Our ability to borrow under our credit facility is subject to certain conditions. At December 31, 2004, we were in compliance with the borrowing conditions of our credit facility and expect that we will be able to borrow under the facility throughout 2005. However, we cannot assure you that we will be able to borrow under our credit facility as necessary to fund our capital expenditures. We also cannot be certain that other additional financing will be available to us on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis. Any such curtailment could have a material adverse effect on our results and future operations.

Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate.

Our reserve data represents the estimates of our reservoir engineers made under the supervision of our management. Our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm. In conducting its audit, the engineers and geologists of Netherland, Sewell & Associates study the Company's major properties in detail and independently develop reserve estimates. Minor properties (typically representing less than 20% of the total reserve estimates) are also audited, but less rigorously. In its report, Netherland, Sewell & Associates treats differences between estimates prepared by us and them that are within 10% in aggregate as immaterial.

Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team in the geographic locations in which the property is located. These estimates are reviewed by senior engineers who are not part of the asset management teams and by the executive vice president of our E&P subsidiaries. Finally, the estimates of our proved reserves together with the audit report of Netherland, Sewell & Associates, Inc. are reviewed by our Audit Committee. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We incorporate many factors and assumptions into our estimates including:

- Expected reservoir characteristics based on geological, geophysical and engineering assessments;
- Future production rates based on historical performance and expected future operating and investment activities;
- Future oil and gas prices and quality and locational differentials; and
- Future development and operating costs.

Although we believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates, our actual results could vary considerably which could cause material variances in the estimated quantities of proved natural gas and oil reserves in the aggregate and for a particular geographic location or future net revenues, including production, revenues, taxes and development and operating expenditures. Any significant variation from these assumptions could result in the actual quantity of our reserves and future net cash flows being materially different from the estimates. In addition, our estimates of reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas and oil prices, operating and development costs and other factors. In 2002, these reserve revisions resulted in a 2.5 Bcfe upward change in our proved reserves in the aggregate. In 2003, reserves were revised downward by 15.5 Bcfe due to poorer-than-expected well performance related to our South Louisiana properties. In 2004, the reserves were also revised downward by 12.7 Bcfe due primarily to slightly higher decline rates related to some of the well in our Overton Field in East Texas. These revisions represented no greater than 3% of our total reserve estimates in each of these years, which we believe is indicative of the effectiveness of our internal controls. Because we review our reserve projections for every property at the end of every year, any material change in a reserve estimate is included in subsequent reserve reports.

Finally, recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. At December 31, 2004, approximately 17% of our estimated proved reserves were undeveloped. Our reserve data assume that we can and will make these expenditures and conduct these operations successfully, which may not occur.

Our level of indebtedness may adversely affect operations and limit our growth.

At December 31, 2004, we had long-term indebtedness of $325.0 million, excluding our several guarantee of NOARK's debt obligation. Of this amount, $100.0 million was bank indebtedness under our then in effect revolving credit facility. As of March 3, 2005, we had approximately $80 million outstanding under our existing $500 million revolving credit facility. As indicated in the risk factor headed "We may have difficulty financing our planned capital expenditures which could adversely affect our growth" above, we also expect to incur significant additional indebtedness in order to fund a portion of capital expenditures in 2005.

The terms of the indenture relating to our outstanding senior notes and our revolving credit facilities impose significant restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, including:

- incurring additional debt, including guarantees of indebtedness;
- redeeming stock or redeeming debt;
- making investments;
- creating liens on our assets; and
- selling assets.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Our ability to comply with the covenants and other restrictions in the agreements governing our debt may be affected by events beyond our control, including prevailing economic and financial conditions. If we fail to comply with the covenants and other restrictions, it could lead to an event of default and the acceleration of our repayment of outstanding debt. We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt. The terms of our debt, including our credit facility and our indentures, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

If we fail to find or acquire additional reserves, our reserves and production will decline materially from their current levels.

The rate of production from natural gas and oil properties generally declines as reserves are depleted. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities, successfully apply new technologies or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as reserves are produced. Future natural gas and oil production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

Our drilling plans for the Fayetteville Shale play are subject to change.

As of December 31, 2004, we have only drilled 21 wells relating to our Fayetteville Shale play. The wells were drilled in areas that represent a very small sample of our large acreage position. Our drilling plans with respect to our Fayetteville Shale play are flexible and are dependent upon a number of factors, including the extent to which we can replicate the results of our most successful Fayetteville Shale wells on our other Fayetteville Shale acreage as well as the gas and oil commodity price environment. The determination as to whether we continue to drill prospects in the Fayetteville Shale may depend on any of the following factors:

- receipt of additional seismic or other geologic data or reprocessing of existing data;
- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- material changes in natural gas prices;
- changes in the estimates of costs to drill or complete wells;
- the extent of our success in drilling and completing horizontal wells;
- our ability to reduce our exposure to costs and drilling risks;
- the costs and availability of drilling equipment; success or failure of wells drilled in similar formations or which would use the same production facilities; or
- availability and cost of capital.

We continue to gather data about our prospects in the Fayetteville Shale, and it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all.

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

We require significant amounts of undeveloped leasehold acreage in order to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We invest in property, including undeveloped leasehold acreage that we believe will result in projects that will add value over time. However, we cannot assure you that all prospects will result in viable projects or that we will not abandon our initial investments. Additionally, there can be no assurance that leasehold acreage acquired 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 leasehold acreage 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 net reserves to return a profit after deducting drilling, operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target PVI results are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and crude 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 leasehold acreage 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 leasehold acreage 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.

In addition, we may not be successful in implementing our business strategy of controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including unexpected drilling conditions, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, environmental and other governmental requirements and the cost of, or shortages or delays in the availability of, drilling rigs, equipment and services.

We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future.

Our exploration, production, development and gas distribution and marketing operations are regulated extensively at the federal, state and local levels. We have made and will continue to make large expenditures in our efforts to comply with these regulations, including environmental regulation. The natural gas and oil regulatory environment could change in ways that might substantially increase these costs. Hydrocarbon-producing states regulate conservation practices and the protection of correlative rights. These regulations affect our operations and limit the quantity of hydrocarbons we may produce and sell. In addition, at the U.S. federal level, the Federal Energy Regulatory Commission regulates interstate transportation of natural gas under the Natural Gas Act. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments.

As an owner or lessee and operator of natural gas and oil properties, and an owner of gas gathering, transmission and distribution systems, we are subject to various federal, state and local regulations relating to discharge of materials into, and protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution clean-up resulting from operations, subject us to liability for pollution damages, and require suspension or cessation of operations in affected areas. Changes in or additions to regulations regarding the protection of the environment could significantly increase our costs of compliance, or otherwise adversely affect our business.

One of the responsibilities of owning and operating natural gas and oil properties is paying for the cost of abandonment. Effective January 1, 2003, companies were required to reflect abandonment costs as a liability on their balance sheets. We may incur significant abandonment costs in the future which could adversely affect our financial results.

Natural gas and oil drilling and producing operations involve various risks.

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties and the drilling of natural gas and oil wells, including encountering well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

We maintain insurance against many potential losses or liabilities arising from our operations in accordance with customary industry practices and in amounts that we believe to be prudent. However, our insurance does not protect us against all operational risks. For example, we do not maintain business interruption insurance. Additionally, pollution and environmental risks generally are not fully insurable. These risks could give rise to significant costs not covered by insurance that could have a material adverse effect upon our financial results.

We cannot control activities on properties we do not operate. Failure to fund capital expenditure requirements may result in reduction or forfeiture of our interests in some of our non-operated projects.

We do not operate some of the properties in which we have an interest and we have limited ability to exercise influence over operations for these properties or their associated costs. Approximately 24% of our gas and oil properties, based on PV10 value, are operated by other companies. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and our targeted production growth rate. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond our control, including the operator's expertise and financial resources, approval of other participants for drilling wells and utilization of technology.

When we are not the majority owner or operator of a particular natural gas or oil project, we may have no control over the timing or amount of capital expenditures associated with such project. If we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Shortages of oil field equipment, services and qualified personnel could adversely affect our results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. There have also been shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher natural gas and oil prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We cannot be certain when we will experience shortages or price increases, which could adversely affect our profit margin, cash flow and operating results or restrict our ability to drill wells and conduct ordinary operations.

Our business could be adversely affected by competition with other companies.

The natural gas and oil industry is highly competitive, and our business could be adversely affected by companies that are in a better competitive position. As an independent natural gas and oil company, we frequently compete for reserve acquisitions, exploration leases, licenses, concessions, marketing agreements, equipment and labor against companies with financial and other resources substantially larger than we possess. Many of our competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating in some of our core areas for a much longer time than we have or have established strategic long-term positions in geographic regions in which we may seek new entry.

We depend upon our management team and our operations require us to attract and retain experienced technical personnel.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy depends, in part, on our experienced management team, as well as certain key geoscientists, geologists, engineers and other professionals employed by us. The loss of key members of our management team or other highly qualified technical professionals could have a material adverse effect on our business, financial condition and operating results.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To reduce our exposure to fluctuations in the prices of natural gas and oil, we enter into hedging arrangements with respect to a portion of our expected production. As of December 31, 2004, we had hedges on approximately 70% to 80% of our targeted 2005 natural gas production and approximately 60% to 70% of our targeted 2005 oil production. Our price risk management activities reduced revenues by $35.6 million in 2004, $37.4 million in 2003 and $6.1 million in 2002. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges.

In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;

- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts natural gas or oil prices.

In addition, future market price volatility could create significant changes to the hedge positions recorded on our financial statements. We refer you to "Quantitative and Qualitative Disclosures about Market Risk."

A decline in the condition of the capital markets or a substantial rise in interest rates could harm us.

If the condition of the capital markets utilized by us to finance our operations materially declines, we might not be able to finance our operations on terms we consider acceptable. In addition, a substantial rise in interest rates would increase the cost of borrowing under our credit facility and decrease our net cash flows.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

"<u>Bcf</u>" One billion cubic feet of gas.

"<u>Bcfe</u>" One billion cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

"<u>Bbl</u>" One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

"<u>Bopd</u>" Barrels of oil produced per day.

"<u>Btu</u>" British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"<u>Dekatherm</u>" A thermal unit of energy equal to 1,000,000 British thermal units (Btu's), that is, the equivalent of 1,000 cubic feet of gas having a heating content of 1,000 Btu's per cubic foot.

"<u>Development drilling</u>" The drilling of a well within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"<u>Downspacing</u>" The process of drilling additional wells within a defined producing area to increase recovery of natural gas and oil from a known reservoir.

"<u>EBITDA</u>" Represents net income attributable to common stock plus interest, income taxes, depreciation, depletion and amortization. We refer you to "Business Overview—Other Items—Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our net income as derived from our audited financial information.

"<u>Exploratory prospects or locations</u>" A location where a well is drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

"<u>Finding and development costs</u>" Costs associated with acquiring and developing proved natural gas and oil reserves which are capitalized pursuant to generally accepted accounting principles, including any capitalized general and administrative expenses.

"<u>Farm-in or farm-out</u>" An agreement under which the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in” while the interest transferred by the assignor is a “farm-out.”

“Gross acreage or gross wells” The total acres or wells, as the case may be, in which a working interest is owned.

“Infill drilling” Drilling wells in between established producing wells, see also “Downspacing.”

“LIBOR” Represents the London Inter-Bank Overnight Rate of interest.

“MBbls” One thousand barrels of crude oil or other liquid hydrocarbons.

“Mcf” One thousand cubic feet of natural gas.

“Mcfe” One thousand cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

“MMBbls” One million barrels of crude oil or other liquid hydrocarbons.

“MMBtu” One million Btu’s.

“MMcf” One million cubic feet of natural gas.

“MMcfe” One million cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

“Net acres or net wells” The sum of the fractional working interests owned in gross acres or gross wells.

“Net revenue interest” Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

“NYMEX” The New York Mercantile Exchange.

“Operating interest” An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

“Play” A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

“Producing property” A natural gas and oil property with existing production.

“Proved developed reserves” Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. For additional information, see the SEC’s definition in Rule 4-10(a)(3) of Regulation S-X, which is available at the SEC’s website, http://www.sec. gov/divisions/corpfin/forms/regsx.htm#gas.

“Proved reserves” The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. For additional information, see the SEC’s definition in Rule 4-10(a)(2)(i) through (iii) of Regulation S-X, which is available at the SEC’s website, http://www.sec. gov/divisions/corpfin/forms/regsx.htm#gas.

“Proved undeveloped reserves” Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units that offset productive units and that are reasonably certain of production when drilled. For additional information, see the SEC’s definition in Rule 4-10(a)(4) of Regulation S-X, which is available at the SEC’s website, http://www.sec. gov/divisions/corpfin/forms/regsx.htm#gas.

"PV-10" When used with respect to natural gas and oil reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as "present value." After-tax PV-10 is also referred to as "standardized measure" and is net of future income tax expense.

"PVI" A measure that is computed for projects by dividing the dollars invested into the PV-10 resulting from the investment.

"Recomplete" This term refers to the technique of drilling a separate well-bore from all existing casing in order to reach the same reservoir, or redrilling the same well-bore to reach a new reservoir after production from the original reservoir has been abandoned.

"Royalty interest" An interest in a natural gas and oil property entitling the owner to a share of oil or gas production free of production costs.

"Step-out well" A well drilled adjacent to a proven well but located in an unproven area; a well located a "step out" from proven territory in an effort to determine the boundaries of a producing formation.

"Undeveloped acreage" Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

"Well spacing" The regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission. The order may be statewide in its application (subject to change for local conditions) or it may be entered for each field after its discovery.

"Working interest" An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

"Workovers" Operations on a producing well to restore or increase production.

"WTI" West Texas Intermediate, the benchmark crude oil in the United States.

ITEM 2. PROPERTIES

For additional information about our natural gas and oil operations, we refer you to Notes 5 and 6 to the financial statements. For information concerning capital expenditures, we refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Expenditures." We also refer you to "Selected Financial Data" for information concerning natural gas and oil produced.

The following information is provided to supplement that presented in Item 8. For a further description of our natural gas and oil properties, we refer you to "Business Overview—Exploration and Production."

Leasehold acreage as of December 31, 2004:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Conventional Arkoma	362,447	293,896	285,323	189,327
Fayetteville Shale Play(1)	673,705	552,689	4,480	4,460
East Texas	18,986	14,850	19,380	16,935
Permian Basin	21,603	13,505	88,936	25,542
Gulf Coast	3,619	2,161	29,601	11,420
Exploration and New Ventures	82,688	47,596	-	-
	1,163,048	924,697	427,720	247,684

(1) Assuming that the Company does not drill successful wells to develop the acreage or does not attempt to extend the leases in our undeveloped acreage, 29,298 net acres will expire in 2007 in the Fayetteville Shale play.

Producing wells as of December 31, 2004:

	Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Conventional Arkoma	890	446.4	-	-	890	446.4	401
Fayetteville Shale Play	10	9.9	-	-	10	9.9	10
East Texas	197	187.6	2	2.0	199	189.6	178
Permian Basin	123	21.8	265	118.9	388	140.7	33
Gulf Coast	46	22.0	18	11.5	64	33.5	25
	1,266	687.7	285	132.4	1,551	820.1	647

Wells drilled during the year:

Exploratory

	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2004	16.0	15.2	5.0	3.7	21.0	18.9
2003	9.0	5.6	1.0	0.6	10.0	6.2
2002	9.0	4.2	6.0	2.7	15.0	6.9

Development

	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2004	150.0	113.0	9.0	2.8	159.0	115.8
2003	101.0	74.6	15.0	5.2	116.0	79.8
2002	36.0	27.5	10.0	5.1	46.0	32.6

Wells in progress as of December 31, 2004:

	Gross	Net
Exploratory	2.0	2.0
Development	22.0	15.3
Total	24.0	17.3

During 2004, we were required to file Form 23, "Annual Survey of Domestic Natural Gas and Oil Reserves," with the Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 6 to the financial statements in Item 8 to this Report. The primary differences are that Form 23 reports gross reserves, including the royalty owners' share, and includes reserves for only those properties where we are the operator.

Miles of Pipe:

The following table provides information concerning miles of pipe of our gas distribution systems. For a further description of Arkansas Western's properties, we refer you to "Business Overview—Natural Gas Distribution."

	Total
Gathering	392
Transmission	1,032
Distribution	3,992
	5,416

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we perform a title investigation that is thorough but less vigorous than that conducted prior to drilling, which is consistent with standard practice in the oil and gas industry. Before we commence drilling operations on those properties that we operate, we conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We have performed a thorough title examination with respect to substantially all of our active properties that we operate.

ITEM 3. LEGAL PROCEEDINGS

We are subject to laws and regulations relating to the protection of the environment. Our policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or reported results of operations.

We are subject to litigation and claims that have arisen in the ordinary course of business. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of our operations or on our financial position.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted during the fourth quarter of the fiscal year ended December 31, 2004, to a vote of security holders, through the solicitation of proxies or otherwise.

Executive Officers of the Registrant

Name	Officer Position	Age	Years Served as Officer
Harold M. Korell	President, Chief Executive Officer and Chairman of the Board	60	8
Greg D. Kerley	Executive Vice President and Chief Financial Officer	49	15
Richard F. Lane	Executive Vice President, Southwestern Energy Production Company and SEECO, Inc.	47	6
Mark K. Boling	Executive Vice President, General Counsel and Secretary	47	3
Alan N. Stewart	Executive Vice President, Arkansas Western Gas Company	60	1

Mr. Korell was elected as Chairman of the Board in May 2002 and has served as Chief Executive Officer since January 1999 and President since October 1998. He joined us in 1997 as Executive Vice President and Chief Operating Officer. From 1992 to 1997, he was employed by American Exploration Company where he was most recently Senior Vice President-Operations. From 1990 to 1992, he was Executive Vice President of McCormick Resources and from 1973 to 1989, he held various positions with Tenneco Oil Company, including Vice President-Production.

Mr. Kerley was appointed to his present position in December 1999. Previously, he served as Senior Vice President and Chief Financial Officer from 1998 to 1999, Senior Vice President-Treasurer and Secretary from 1997 to 1998, Vice President-Treasurer and Secretary from 1992 to 1997, and Controller from 1990 to 1992. Mr. Kerley also served as the Chief Accounting Officer from 1990 to 1998.

Mr. Lane was appointed to his present position in December 2001. Previously, he served as Senior Vice President from February 2001 and Vice President-Exploration from February 1999. Mr. Lane joined us in February 1998 as Manager-Exploration. From 1993 to 1998, he was employed by American Exploration Company where he was most recently Offshore Exploration Manager. Previously, he held various managerial and geological positions at FINA, Inc. and Tenneco Oil Company.

Mr. Boling was appointed to his present position in December 2002. He joined us as Senior Vice President, General Counsel and Secretary in January 2002. Prior to joining the Company, Mr. Boling had a private law practice in Houston specializing in the natural gas and oil industry from 1993 to 2002. Previously, Mr. Boling was a partner with Fulbright and Jaworski L.L.P. where he was employed from 1982 to 1993.

Mr. Stewart was appointed to his current position effective March 2004. Prior to joining the Company, he provided professional consulting services for clients in the energy and LNG industries in California. Previously, Mr. Stewart was employed with San Diego Gas and Electric Company and Southern California Gas Company where he served in a wide range of managerial and leadership positions during a 31-year career.

All officers are elected at the Annual Meeting of the Board of Directors for one-year terms or until their successors are duly elected. There are no arrangements between any officer and any other person pursuant to which he was selected as an officer. There is no family relationship between any of the named executive officers or between any of them and our directors.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol "SWN." At December 31, 2004, we had 2,022 shareholders of record. The following prices represent closing market transactions on the New York Stock Exchange.

	Range of Market Prices			
Quarter Ended	**2004**		**2003**	
March 31	$24.45	$19.35	$13.23	$10.91
June 30	$28.67	$23.86	$16.35	$12.70
September 30	$42.38	$29.67	$18.55	$14.24
December 31	$54.90	$41.30	$25.48	$18.13

We have indefinitely suspended payment of quarterly cash dividends on our common stock.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2004. This information and the notes thereto are derived from our financial statements. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Financial Statements and Supplementary Data."

	2004	2003	2002	2001	2000
	(in thousands except share, per share, shareholder data and percentages)				
Financial Review					
Operating revenues					
Exploration and production	$ 286,924	$ 176,245	$ 122,207	$ 153,937	$ 110,920
Gas distribution	152,449	137,356	115,850	147,282	151,234
Gas marketing and other	321,226	205,449	131,514	190,773	208,196
Intersegment revenues	(283,462)	(191,649)	(108,069)	(147,065)	(106,467)
	477,137	327,401	261,502	344,927	363,883
Operating costs and expenses					
Gas purchases - utility	64,311	52,585	48,388	68,161	58,669
Gas purchases - marketing	60,804	39,428	37,927	68,010	133,221
Operating and general	78,231	70,479	64,600	64,108	59,790
Unusual items	—	—	—	—	111,288
Depreciation, depletion and amortization	73,674	55,948	53,992	52,899	45,869
Taxes, other than income taxes	17,830	11,619	10,090	9,080	8,515
	294,850	230,059	214,997	262,258	417,352
Operating income (loss)	182,287	97,342	46,505	82,669	(53,469)
Interest expense, net	(16,992)	(17,311)	(21,466)	(23,699)	(24,689)
Other income (expense)	(362)	797	(566)	(799)	1,997
Minority interest in partnership	(1,579)	(2,180)	(1,454)	(930)	—
Income (loss) before income taxes and accounting change	163,354	78,648	23,019	57,241	(76,161)
Income taxes					
Current	—	—	—	—	—
Deferred	59,778	28,896	8,708	21,917	(29,474)
	59,778	28,896	8,708	21,917	(29,474)
Income before accounting change	103,576	49,752	14,311	35,324	(46,687)
Cumulative effect of adoption of accounting principle	—	(855)	—	—	—
Net income (loss)	$ 103,576	$ 48,897	$ 14,311	$ 35,324	$ (46,687)
Net cash provided by operating activities	$ 237,897	$ 109,099	$ 77,574	$ 144,583	$ (53,203)(1)
Return on equity	23.1%	14.3%	8.1%	19.3%	n/a
Common Stock Statistics					
Earnings (loss) per share:					
Basic	$ 2.90	$ 1.46	$ .57	$ 1.40	$ (1.86)
Diluted	$ 2.80	$ 1.43	$ .55	$ 1.38	$ (1.86)
Cash dividends declared and paid per share	$ —	$ —	$ —	$ —	$ .12
Book value per average diluted share	$ 12.11	$ 9.98	$ 6.81	$ 7.15	$ 5.64
Market price at year-end	$ 50.69	$ 23.90	$ 11.45	$ 10.40	$ 10.38
Number of shareholders of record at year-end	2,022	2,026	2,079	2,124	2,192
Average diluted shares outstanding	36,962,772	34,237,934	26,052,238	25,601,110	25,043,586

(1) Net cash provided by operating activities for 2000 would have been $58.1 million excluding the effects of unusual items for the Hales judgment and other litigation.

	2004	2003	2002	2001	2000
Capitalization (in thousands)					
Total debt, including current portion	$ 325,000	$ 278,800	$ 342,400	$ 350,000	$ 396,000
Common shareholders' equity[1]	447,677	341,561	177,488	183,086	141,291
Total capitalization	$ 772,677	$ 620,361	$ 519,888	$ 533,086	$ 537,291
Total assets	$ 1,146,144	$ 890,710	$ 740,162	$ 743,123	$ 705,378
Capitalization ratios:					
Debt	42.1%	44.9%	65.9%	65.7%	73.7%
Equity	57.9%	55.1%	34.1%	34.3%	26.3%
Capital Expenditures (in millions) [2]					
Exploration and production	$ 282.0	$ 170.9	$ 85.2	$ 99.0	$ 69.2
Gas distribution	7.3	8.2	6.1	5.3	6.0
Other	5.7	1.1	0.8	1.8	0.5
	$ 295.0	$ 180.2	$ 92.1	$ 106.1	$ 75.7
Exploration and Production					
Natural gas:					
Production, Bcf	50.4	38.0	36.0	35.5	31.6
Average price per Mcf, including hedges	$ 5.21	$ 4.20	$ 3.00	$ 3.85	$ 2.88
Average price per Mcf, excluding hedges	$ 5.80	$ 5.15	$ 3.11	$ 4.16	$ 3.92
Oil:					
Production, MBbls	618	531	682	719	676
Average price per barrel, including hedges	$ 31.47	$ 26.72	$ 21.02	$ 23.55	$ 22.99
Average price per barrel, excluding hedges	$ 40.55	$ 29.66	$ 23.94	$ 23.58	$ 29.38
Total gas and oil production, Bcfe	54.1	41.2	40.1	39.8	35.7
Lease operating expenses per Mcfe	$ .38	$ .39	$ .45	$ .45	$ .40
Taxes other than income taxes per Mcfe	$ .28	$ .22	$ .19	$ .17	$ .16
Proved reserves at year-end:					
Natural gas, Bcf	594.5	457.0	374.6	355.8	331.8
Oil, MBbls	8,508	7,675	6,784	7,704	8,130
Total reserves, Bcfe	645.5	503.1	415.3	402.0	380.6
Gas Distribution[3]					
Sales and transportation volumes, Bcf:					
Residential	8.5	9.0	9.0	8.4	7.9
Commercial	5.7	6.1	6.2	6.1	6.0
Industrial	1.3	1.2	1.5	2.5	2.9
End-use transportation	8.5	8.4	8.4	7.0	6.3
	24.0	24.7	25.1	24.0	23.1
Off-system transportation	1.0	0.3	2.2	3.1	3.1
	25.0	25.0	27.3	27.1	26.2
Customers at year-end:					
Residential	127,622	124,776	122,906	119,856	119,024
Commercial	16,815	16,623	16,448	16,177	16,282
Industrial	175	174	189	209	228
	144,612	141,573	139,543	136,242	135,534
Degree days	3,678	3,969	3,950	3,654	3,994
Percent of normal	90%	99%	98%	91%	100%

(1) Shareholders' equity included accumulated other comprehensive losses of $19.8 million in 2004 ($18.8 million related to our cash flow hedges and $1.0 million related to our pension plan), $12.5 million in 2003 ($12.0 million related to our cash flow hedges and $0.5 million related to our pension plan), and $17.4 million in 2002 ($14.0 million related to our cash flow hedges and $3.4 million related to our pension plan), and accumulated other comprehensive income of $5.8 million in 2001 related to our cash flow hedges.

(2) Capital expenditures for 2004 and 2003 included $3.9 million and $12.0 million, respectively, related to the change in accrued expenditures between years.

(3) Gas distribution statistics for 2000 exclude the operations of Missouri properties which were sold May 31, 2000.

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

This Form 10-K contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in "Risk Factors" and elsewhere in this annual report. You should read the following discussion with the "Selected Financial Data" and our financial statements and related notes included elsewhere in this Form 10-K.

OVERVIEW

Southwestern Energy Company is an integrated energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We also operate integrated natural gas distribution systems in northern Arkansas. As a complement to our other businesses, we provide marketing services in each of our core areas of operation. We operate our business in three segments: Exploration and Production, Natural Gas Distribution and Natural Gas Marketing.

Our business strategy is focused on providing long-term growth in the net asset value of our business. We prepare economic analyses for each of our drilling and acquisition opportunities and rank them based upon the expected present value added for each dollar invested, which we refer to as PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. We target creating at least $1.30 of discounted pre-tax PVI for each dollar we invest in our Exploration and Production, or E&P, business. Our actual PVI results are utilized to help determine the allocation of our future capital investments. We are also focused on creating and capturing additional value beyond the wellhead through our natural gas distribution, marketing and transportation businesses.

In 2004, our gas and oil production continued to increase, reaching 54.1 Bcfe, up from 41.2 Bcfe in 2003 and 40.1 Bcfe in 2002. The 31% increase in 2004 production resulted from an increase in production from our Overton Field in East Texas due to accelerated development, increased production in the Arkoma Basin and production from our River Ridge discovery in New Mexico.

Our financial and operating results depend on a number of factors, including in particular natural gas and oil prices, our ability to find and produce natural gas and oil, our ability to control costs, the seasonality of our customers' needs for natural gas and our ability to market natural gas and oil on economically attractive terms to our customers, all of which are dependent upon numerous factors beyond our control such as economic, political and regulatory developments and competition from other energy sources. There has been significant price volatility in the natural gas and crude oil market in recent years. The volatility was attributable to a variety of factors impacting supply and demand, including weather conditions, political events and economic events we cannot control or predict.

We reported net income of $103.6 million in 2004, or $2.80 per share on a fully diluted basis, up from $48.9 million, or $1.43 per share in 2003. In 2002, we reported net income of $14.3 million, or $0.55 per share on a fully diluted basis. The increases in net income in 2004 and 2003 were a result of increased production volumes and higher realized natural gas and oil prices in our E&P segment with higher gas prices being the primary factor in 2003. Operating income for our E&P segment was $164.6 million in 2004, up from $84.7 million in 2003 and $36.0 million in 2002. The increases in operating income for our E&P segment in 2004 and 2003 were also due to increased production volumes and higher realized prices. Operating income for our gas distribution segment was $8.5 million in 2004, compared to $6.8 million in 2003 and $7.6 million in 2002. The increase in operating income for our gas distribution segment in 2004 resulted primarily from increased rates implemented in October 2003. Our cash flow from operating activities was $237.9 million in 2004, compared to $109.1 million in 2003 and $77.6 million in 2002.

In our E&P segment, we achieved a reserve replacement ratio of 365% in 2004 at a finding and development cost of $1.43 per Mcfe, including reserve revisions. Our year-end reserves grew 28% to 645.5 Bcfe, up from 503.1 Bcfe at the end of 2003. Our results were primarily fueled by our continued drilling success in our Overton Field in East Texas as well as our continued successful conventional drilling program in the Arkoma Basin.

Our capital investments totaled $295.0 million in 2004, up from $180.2 million in 2003 and $92.1 million in 2002. We invested $282.0 million in our E&P segment in 2004, compared to $170.9 million in 2003 and $85.2 million in 2002. Funds for our 2004 capital investments were provided by cash flow from operations and borrowings under our unsecured revolving line of credit.

Our cash flow and earnings provided by operating results in 2004 helped us to decrease our total debt-to-capitalization ratio to 42% at December 31, 2004, compared to 45% at December 31, 2003.

Capital investments for 2005 are planned to be up to $352.7 million, including up to $339.0 million for our E&P segment, which is an increase of 20% over our E&P capital investments in 2004. The $339.0 million of exploration and production investments includes up to $100.2 million for the accelerated development of our Fayetteville Shale play that was announced during 2004, assuming that we continue to be encouraged by our drilling results. We continue to be focused on our strategy of adding value through the drillbit, as over 80% of our 2005 E&P capital is allocated to drilling. In addition to the planned investments in the Fayetteville Shale play, our E&P investments in 2005 will primarily be focused on our lower-risk development drilling programs in East Texas and other conventional drilling in the Arkoma Basin. In 2005, we are targeting production to be approximately 61.0 Bcfe to 63.0 Bcfe, compared to 54.1 Bcfe in 2004, an increase of approximately 13% to 17%. We expect our capital investments in 2005 will be funded by cash flow from operations and borrowings under our revolving credit facility.

With today's commodity price environment, our current capital program and our inventory of projects for the future, we believe we are well-positioned to continue to build upon the momentum achieved in recent years.

RESULTS OF OPERATIONS

Exploration and Production

	Year Ended December 31,		
	2004	2003	2002
Revenues (in thousands)	$286,924	$176,245	$122,207
Operating income (in thousands)	$164,585	$ 84,737	$ 36,048
Gas production (Bcf)	50.4	38.0	36.0
Oil production (MBbls)	618	531	682
Total production (Bcfe)	54.1	41.2	40.1
Average gas price per Mcf, including hedges	$ 5.21	$ 4.20	$ 3.00
Average gas price per Mcf, excluding hedges	$ 5.80	$ 5.15	$ 3.11
Average oil price per Bbl, including hedges	$ 31.47	$ 26.72	$ 21.02
Average oil price per Bbl, excluding hedges	$ 40.55	$ 29.66	$ 23.94
Average unit costs per Mcfe			
Lease operating expenses	$ 0.38	$ 0.39	$ 0.45
General & administrative expenses	$ 0.36	$ 0.41	$ 0.32
Taxes other than income taxes	$ 0.28	$ 0.22	$ 0.19
Full cost pool amortization	$ 1.20	$ 1.17	$ 1.16

Revenues, Operating Income and Production

Revenues. Our E&P revenues increased 63% in 2004 to $286.9 million compared to $176.2 million in 2003. Increased gas production volumes and higher prices received for our natural gas and oil production contributed equally to the increased revenues. Revenues increased 44% in 2003 from $122.2 million in 2002. The increase was primarily due to higher prices received for our natural gas and oil production. Future changes in revenue can not be predicted reliably due to the market volatility of natural gas and crude oil prices.

Operating Income. Operating income from our E&P segment was $164.6 million in 2004, up from $84.7 million in 2003 and $36.0 million in 2002. The increases in 2004 and 2003 were due to the increases in revenues, partially offset by increases in operating costs and expenditures.

Production. Gas and oil production totaled 54.1 Bcfe in 2004, 41.2 Bcfe in 2003 and 40.1 Bcfe in 2002. The increase in 2004 production resulted primarily from an 8.2 Bcfe increase in production from our Overton Field in East Texas, a 1.3 Bcfe increase in our Arkoma Basin production, and 3.2 Bcfe from our River Ridge discovery in New Mexico. The increase in 2003 production resulted from a 7.7 Bcfe increase in production from our Overton Field, partially offset by a 3.3 Bcfe decline experienced in our South Louisiana properties and a loss of production resulting from the November 2002 sale of our non-strategic Mid-Continent properties that contributed approximately 2.5 Bcfe of production annually.

Although we expect production volumes in the near-term to increase, we cannot guarantee our longer-term success in discovering, developing, and producing reserves. Our ability to discover, develop and produce reserves is dependent upon a number of factors, many of which are beyond our control, including the availability of capital, the timing and extent of changes in natural gas and oil prices and competition. There are also many risks inherent to the discovery, development and production of natural gas and oil. We refer you to “Risk Factors” in Item 1 of Part I of this Form 10-K for a discussion of these risks and the impact they could have on our financial condition and results of operations.

Gas sales to unaffiliated purchasers were 45.0 Bcf in 2004, up from 32.1 Bcf in 2003 and 30.6 Bcf in 2002. Sales to unaffiliated purchasers are primarily made under contracts that reflect current short-term prices and are subject to seasonal price swings. Intersegment sales to Arkansas Western were 5.4 Bcf in 2004, 5.9 Bcf in 2003 and 5.4 Bcf in 2002. The changes in intersegment sales volumes reflect both the effects of weather and the ability of our E&P segment to obtain gas supply contracts that are periodically placed out for bids. Weather in 2004, as measured in degree days, was 10% warmer than normal and 9% warmer than the prior year. Weather in 2003 was 1% warmer than normal and slightly above the prior year. Our gas production provided approximately 40% of the utility's requirements in 2004, 41% in 2003 and 37% in 2002.

We expect future increases in demand for our gas production to come primarily from sales to unaffiliated purchasers. Future sales to Arkansas Western's gas distribution systems will be dependent upon our success in obtaining gas supply contracts with the utility systems. We expect to continue to bid to obtain these gas supply contracts, however there can be no assurance that we will be successful. If successful, we cannot predict the amount of fixed demand charges, if any, that would be associated with the new contracts. We also sell gas directly to industrial and commercial transportation customers located on Arkansas Western’s gas distribution systems. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand of both affiliated and unaffiliated customers for our production. Additionally, we hold a large amount of undeveloped leasehold acreage and producing acreage, and have an inventory of drilling leads, prospects and seismic data that will continue to be evaluated and developed in the future. Our exploration programs have been directed primarily toward natural gas in recent years.

Commodity Prices

In order to ensure certain levels of cash flow, we periodically enter into hedging activities with respect to a portion of our projected natural gas and crude oil production through a variety of financial arrangements intended to support natural gas and oil prices at targeted levels and to minimize the impact of price fluctuations (we refer you to Item 7A of this Form 10-K and Note 8 to the consolidated financial statements for additional discussion). The average price realized for our gas production, including the effects of hedges, was $5.21 per Mcf in 2004, $4.20 per Mcf in 2003 and $3.00 per Mcf in 2002. The changes in the average price realized primarily reflect changes in average annual spot market prices and the effects of our price hedging activities. Our hedging activities lowered the average gas price $0.59 per Mcf in 2004, $0.95 per Mcf in 2003 and $0.11 per Mcf in 2002. Additionally, we have historically received demand charges related to sales made to our utility segment, which has increased our average gas price realized. Disregarding the impact of hedges, we would normally expect the average price received for our gas production to be approximately $0.30 to $0.50 per Mcf lower than average spot market prices, as market differentials that reduce the average prices received are partially offset by demand charges received under the contracts covering our intersegment sales to our utility systems.

We realized an average price of $31.47 per barrel, including the effects of hedges, for our oil production for the year ended December 31, 2004, up from $26.72 per barrel for 2003 and $21.02 per barrel for 2002. Our hedging activities lowered the average oil price $9.08 per barrel in 2004, $2.94 per barrel in 2003 and $2.92 per barrel in 2002. Disregarding the impact of hedges, we expect the average price received for our oil production to be approximately $1.25 lower than posted spot market prices.

At December 31, 2004, we had hedges in place on 71.6 Bcf of 2005 and 2006 gas production. At December 31, 2004 we had hedges in place on 480,000 barrels of 2005 and 2006 oil production. Subsequent to December 31, 2004 and prior to March 3, 2005, we hedged 4.0 Bcf of 2006 gas production under costless collars with floor prices of $5.50 per Mcf and ceiling prices ranging from $7.60 to $13.50 per Mcf. As of March 3, 2005, we have hedged approximately 70% to 80% of our 2005 anticipated gas production level and 60% to 70% of our 2005 anticipated oil production level.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.38 in 2004, down from $0.39 in 2003 and $0.45 in 2002. Lease operating expenses per unit of production decreased in 2004 due primarily to a 31% increase in our production volumes. In 2004, lease operating expenses per unit averaged $0.18 per Mcfe for Overton Field and $0.31 per Mcfe for our conventional Arkoma Basin production. These two areas accounted for 78% of our total production in 2004. Although the per unit operating costs for these areas will continue to remain low compared to other operating areas, they will increase over time due to the natural maturing of the fields and inflationary pressures on total costs. We do not have sufficient operating history for our Fayetteville Shale play to forecast with accuracy the future operating costs that we may incur assuming the successful development of this play.

Taxes other than income taxes per Mcfe were $0.28 in 2004, compared to $0.22 in 2003 and $0.19 in 2002. The increase in 2004 taxes other than income taxes per Mcfe was due to increased severance and ad valorem taxes that resulted from increases in commodity prices and from the changing mix of our production among taxing jurisdictions.

General and administrative expenses per Mcfe for this segment were $0.36 in 2004, compared to $0.41 in 2003 and $0.32 in 2002. The decrease in general and administrative costs per Mcfe in 2004 from 2003 was due primarily to the 31% increase in production volumes, partially offset by an 18% increase in general and administrative expenses for this segment. Increased payroll and incentive compensation costs, partially offset by decreased pension expense and an increase in costs capitalized to the full cost pool under full cost accounting rules, accounted for the increase in general and administrative costs.

We expect our cost per Mcfe for operating and general and administrative expenses to increase in 2005 primarily due to anticipated increases in oil field service costs and an increase in our staffing levels to accommodate our future expected growth. Future changes in our general and administrative expenses for this segment are primarily dependent upon our salary costs, level of pension expense and the amount of incentive compensation paid to our employees. Incentive compensation is based on operating and performance results. See "Critical Accounting Policies" below for further discussion of pension expense.

Our full cost pool amortization rate averaged $1.20 per Mcfe for 2004, compared to $1.17 in 2003 and $1.16 in 2002. The amortization rate is impacted by reserve additions and the costs incurred for those additions, revisions of previous reserve estimates due to both price and well performance, and the level of unevaluated costs excluded from amortization. Although we expect our amortization rate to continue to increase in the near term as a result of increased costs in finding and developing gas and oil reserves (see discussion on inflation below), we cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as the uncertainty of the future success of our Fayetteville Shale play. Unevaluated costs excluded from amortization were $47.2 million at the end of 2004, compared to $39.0 million at the end of 2003 and $25.5 million at the end of 2002. The increase in unevaluated costs since December 31, 2002 primarily resulted from an increase in our undeveloped leasehold acreage related to our Fayetteville Shale play.

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under this method, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of this ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. At December 31, 2004, 2003 and 2002, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2004, our standardized measure was calculated based upon quoted market prices of $6.18 per Mcf for Henry Hub gas and $43.45 per barrel for West Texas Intermediate oil, adjusted for market differentials. A decline in natural gas and oil prices from year-end 2004 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

In November 2002, we sold our remaining non-strategic Mid-Continent properties, including our properties in the Sho-Vel-Tum area in southern Oklahoma, the Anadarko Basin in western Oklahoma and the Sooner Trend in northwestern Oklahoma, for a total of $26.4 million. These properties represented approximately 32.9 Bcfe of reserves and produced approximately 2.5 Bcfe annually. This divestiture, along with increased production from the Overton Field, resulted in a decrease in our average production costs per unit of production in 2003.

Inflation impacts our E&P operations by generally increasing our operating costs and the costs of our capital additions. The effects of inflation on our operations prior to 2000 have been minimal due to low inflation rates. However, since 2001, the impact of inflation has intensified in certain areas of our exploration and production segment as shortages in drilling rigs, third-party services and qualified labor developed due to an overall increase in the activity level of the domestic natural gas and oil industry. We feel this impact increased in 2004 and 2003 with increases in the industry activity level caused by higher commodity prices. We have mitigated rising costs in certain situations by obtaining vendor commitments to multiple projects and by offering performance bonuses related to increased efficiencies.

Natural Gas Distribution

	Year Ended December 31,		
	2004	2003	2002
	($ in thousands except for per Mcf amounts)		
Revenues	$152,449	$137,356	$115,850
Gas purchases	$ 97,274	$ 84,926	$ 66,486
Operating costs and expenses	$ 46,659	$ 45,664	$ 41,801
Operating income	$ 8,516	$ 6,766	$ 7,563
Deliveries (Bcf)			
Sales and end-use transportation	24.0	24.7	25.1
Off-system transportation	1.0	0.3	2.2
Customers at year-end	144,612	141,573	139,543
Average sales rate per Mcf	$ 9.39	$ 7.93	$ 6.49
Heating weather - degree days	3,678	3,969	3,950
Percent of normal	90%	99%	98%

Revenues and Operating Income

Gas distribution revenues fluctuate due to the effects of warm weather on demand for natural gas and the pass-through of gas supply cost changes. Because of the corresponding changes in purchased gas costs, the revenue effect of the pass-through of gas cost changes has not materially affected operating income.

Gas distribution revenues increased 11% in 2004 and 19% in 2003. The increase in 2004 gas distribution revenues was primarily due to higher average sales rates as a result of higher gas prices and to the effects of a $4.1 million annual rate increase implemented in October 2003. The increase in 2003 gas distribution revenues was primarily due to a higher average sales rate caused by higher gas prices. Weather during 2004 in the utility's service territory was 10% warmer than normal and 9% warmer than the prior year. Weather during 2003 was 1% warmer than normal and slightly above the prior year.

Operating income for our utility systems increased 26% in 2004 and decreased 11% in 2003. The increase in 2004 operating income for this segment resulted primarily from rate increases implemented in late 2003 partially offset by increased operating costs and expenses. The decrease in 2003 operating income for this segment resulted from increased operating costs and expenses and reduced usage per customer due to customer conservation brought about by high gas prices. In October 2003, we implemented a rate increase that increased revenue and operating income by $4.1 million annually (see “Regulatory Matters” below for a discussion of the rate increase) and were also allowed to recover certain additional costs totaling $2.3 million over a two-year period. Gas distribution revenues in future years will be impacted by the utility's gas purchase costs, customer growth, usage per customer and rate increases allowed by the Arkansas Public Service Commission, or APSC. In recent years, Arkansas Western has experienced customer growth of approximately 2% annually in its Northwest Arkansas service territory, while it has experienced little or no customer growth in its service territory in Northeast Arkansas. Based on current economic conditions in our service territories, we expect this trend in customer growth to continue. While our utility segment’s results have improved since last year, we do not believe that it is earning its authorized rate of return. As a result, and as discussed below in “Regulatory Matters,” on December 29, 2004, we filed a rate increase request for $9.7 million with the APSC.

Deliveries and Rates

In 2004, Arkansas Western sold 15.5 Bcf to its customers at an average rate of $9.39 per Mcf, compared to 16.3 Bcf at $7.93 per Mcf in 2003 and 16.7 Bcf at $6.49 per Mcf in 2002. Additionally, Arkansas Western transported 8.5 Bcf in 2004 and 8.4 Bcf in 2003 and 2002 for its end-use customers. The decreases in volumes sold in 2004 and 2003 primarily resulted from variations in weather and customer conservation brought about by high gas prices in recent years. Arkansas Western's tariffs contain a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The increase in the utility segment's average sales rate for 2004 reflected changes in the average cost of gas purchased for delivery to our customers, which are passed through to customers under automatic adjustment clauses.

Total deliveries to industrial customers of the utility segment, including transportation volumes, were 9.8 Bcf in 2004, 9.6 Bcf in 2003 and 9.9 Bcf in 2002. Changes in deliveries to industrial customers were impacted by customer conservation caused by high gas prices partially offset by continued industrial growth in the region. Arkansas Western also transported 1.0 Bcf of gas through its gathering system in 2004 compared to 0.3 Bcf in 2003 and 2.2 Bcf in 2002 for off-system deliveries, all to the Ozark Gas Transmission System. The level of off-system deliveries each year generally reflects the impact of weather changing the on-system demands of our gas distribution systems for our gas production. The average off-system transportation rate was approximately $0.13 per Mcf, exclusive of fuel, in 2004, 2003 and 2002.

Future volumes delivered to customers will be impacted by customer growth, weather and the effect that gas prices will continue to have on customer conservation.

Operating Costs and Expenses

The changes in purchased gas costs for the gas distribution segment reflect volumes purchased, prices paid for supplies and the mix of purchases from various gas supply contracts (base load, swing and no-notice). Operating costs and expenses, net of purchased gas costs, increased in 2004 to $46.7 million from $45.7 million in 2003. The increase was primarily due to a $0.6 million increase in transmission expense as a result of higher fuel costs and a $0.3 million increase in depreciation expense as a result of increases in property, plant and equipment. Operating costs and expenses, net of purchased gas costs, for 2003 increased to $45.7 million from $41.8 million in 2002 due primarily to a $2.6 million increase in general and administrative expenses and a $0.8 million increase in transmission expense. The increase in 2003 general and administrative expenses resulted from increased pension, insurance and incentive compensation costs. The increase in 2003 transmission expense resulted from higher fuel costs. Future changes in our general and administrative expenses for this segment are primarily dependent upon our salary costs, level of pension expense and the amount of incentive compensation paid to our employees. See "Critical Accounting Policies" below for further discussion of pension expense.

In October 1998, Arkansas Western instituted a competitive bidding process for its gas supply. Additionally, Arkansas Western annually submits its gas supply plan to the general staff of the APSC. As a result of the bidding process under the plan filed for the 2004-2005 gas purchase year, SEECO successfully bid on gas supply packages representing approximately 55% of the requirements for Arkansas Western for 2005. The contracts awarded to SEECO expire through 2006. Arkansas Western enters into hedging activities from time to time with respect to its gas purchases to protect against the inherent price risks of adverse price fluctuations. Our utility segment hedged 4.5 Bcf of gas purchases in 2004 which had the effect of decreasing its total gas supply costs by $1.1 million. In 2003, our utility hedged 4.6 Bcf of its gas supply which decreased its total gas supply cost by $6.1 million. In 2002, our utility hedged 4.7 Bcf of its gas supply which increased its total gas supply cost by $5.7 million. At December 31, 2004, Arkansas Western had 2.9 Bcf of future gas purchases hedged at an average purchase price of $6.54 per Mcf. We refer you to "Quantitative and Qualitative Disclosures About Market Risk" and Note 8 to the consolidated financial statements for additional information.

Inflation impacts our gas distribution segment by generally increasing our operating costs and the costs of our capital additions. The effects of inflation on the utility's operations in recent years have been minimal due to low inflation rates. Additionally, delays inherent in the rate-making process prevent us from obtaining immediate recovery of increased operating costs of our gas distribution segment.

Regulatory Matters

Arkansas Western's rates and operations are regulated by the APSC. Arkansas Western operates through municipal franchises that are perpetual by virtue of state law, but may not be exclusive within a geographic area. Although its rates for gas delivered to its retail customers are not regulated by the FERC, its transmission and gathering pipeline systems are subject to the FERC's regulations concerning open access transportation. As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation have unbundled residential sales services from transportation services in an effort to promote greater competition. No such legislation or regulatory directives related to natural gas are presently pending in Arkansas and we have not unbundled our residential sales services.

In 2003, Arkansas Act 1556 for the deregulation of the retail sale of electricity was repealed. During 2004, the APSC conducted collaborative meetings to study the feasibility of a large-user access program for electric service choice. On September 30, 2004, the APSC issued a report to the legislature finding that it would not be feasible to implement a large-user access program without shifting costs to other customer classes and recommending that no changes be made to the statutes which would affect access to competitive power supply by large users. We do not know what action the legislature may take in response to this report. Although Arkansas Western already provides transportation service for its large users, any developments regarding large-user access programs for electricity could set regulatory precedents that would also affect natural gas utilities in the future. These effects may include protection of other customer classes against cost shifting and the regulatory treatment of stranded costs.

In 2004, our analysis indicated that current revenues in our utility segment were not sufficient to cover the cost of providing utility service and earn the rate of return authorized by the APSC. Arkansas Western's northwest Arkansas service area includes one of the fastest growing areas of the United States. However, declining consumption per residential customer has offset much of the revenue benefit of strong customer growth. Arkansas Western believes this declining consumption is a trend attributable to rising natural gas prices resulting in energy conservation in existing homes such as reducing thermostat settings, caulking, adding insulation and the replacement of older natural gas equipment with high efficiency equipment. As a result of the decline in consumption coupled with increases in operating cost and capital investments, on December 29, 2004, the gas distribution subsidiary filed a request with the APSC for an adjustment in its rates totaling $9.7 million, or 5.2%, annually. The APSC has ten months to review the filing and determine the amount of the increase to be approved, if any. Any rate increase allowed would likely be implemented in the fourth quarter of 2005.

In September 2003, in response to our request for an $11.0 million rate increase, Arkansas Western received regulatory approval from the APSC of a rate increase totaling $4.1 million annually, exclusive of costs to be recovered through Arkansas Western’s purchase gas adjustment clause. The order also entitled Arkansas Western to recover certain additional costs totaling $2.3 million through its purchase gas adjustment clause over a two-year period. The rate increase was effective for all customer bills rendered on or after October 1, 2003.

In the rate increase request relating to the 2003 increase, we assumed an allowed return on equity of 12.9% and a capital structure of 48% debt and 52% equity. The final order provided for an allowed return on equity of 9.9% and an assumed capital structure of 52% debt and 48% equity. In our 2004 filing, we assumed a rate of return of 11.5% and a capital structure of 50% debt and 50% equity. Rate increase requests, which may be filed in the future, will depend on customer growth, increases in operating expenses, and additional investment in property, plant and equipment.

In February 2001, the APSC approved a 90-day temporary tariff to collect additional gas costs not yet billed to customers through the utility's normal purchased gas adjustment clause in its approved tariffs. We had significant under-recovered purchased gas costs as a result of the high prices paid for gas supply in the 2000-2001 heating season. The temporary tariff allowed the utility accelerated recovery of these gas costs. In April 2002, Arkansas Western filed a revised purchased gas adjustment clause that provides better matching between the time the gas costs are incurred and the time the costs are recovered. The APSC approved the new clause in May 2002 and it is still in effect.

In April 2002, the APSC adopted Natural Gas Procurement Plan Rules for utilities. These rules require utilities to take all reasonable and prudent steps necessary to develop a diversified gas supply portfolio. The portfolio should consist of an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments that are designed to yield an optimum balance of reliability, reduced volatility and reasonable price. Utilities are also required to submit on an annual basis their gas supply plan, along with their contracting and/or hedging objectives, to the staff of the APSC for review and determination as to whether it is consistent with these policy principles. In May 2004, Arkansas Western submitted its annual gas supply plan for the 2004-2005 heating season to the staff of the APSC.

Arkansas Western also purchases gas from unaffiliated producers under take-or-pay contracts. We believe that we do not have significant exposure to liabilities resulting from these contracts and expect to be able to continue to satisfactorily manage our exposure to take-or-pay liabilities.

Marketing

	Year Ended December 31,		
	2004	2003	2002
Revenues (in millions)	$ 315.0	$ 202.0	$ 131.1
Operating income (in millions)	$ 3.2	$ 2.6	$ 2.7
Gas volumes marketed (Bcf)	57.0	42.7	45.5

Our operating income from natural gas marketing was $3.2 million on revenues of $315.0 million in 2004, compared to $2.6 million on revenues of $202.0 million in 2003 and $2.7 million on revenues of $131.1 million in 2002. The increase in revenues in 2004 resulted from increased volumes marketed and higher prices received for gas sold. The increase in revenues from higher prices was largely offset by a corresponding increase in gas purchase expense. We marketed 57.0 Bcf in 2004, compared to 42.7 Bcf in 2003 and 45.5 Bcf in 2002. The increase in volumes marketed in 2004 resulted from marketing our increased production volumes, largely related to our Overton Field in East Texas. The decline in total volumes marketed between 2003 and 2002 resulted primarily from a shift in our focus to marketing our own production in order to reduce our credit risk. Of the total volumes marketed, production from our exploration and production subsidiaries accounted for 77% in 2004, 75% in 2003 and 67% in 2002. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to “Quantitative and Qualitative Disclosures About Market Risk” and Note 8 to the financial statements for additional discussion.

Transportation

Our marketing group also manages our 25% interest in the Ozark Gas Transmission System. Additionally, our gas distribution subsidiary has a transportation contract with Ozark Gas Transmission System for 66.9 MMcf per day of firm capacity that expires in 2014. We recorded a pre-tax loss from operations related to our investment of $0.4 million in 2004, compared to pre-tax income of $1.1 million in 2003 and a pre-tax loss of $0.3 million in 2002. These amounts are recorded in other income (expense) in our income statement. The pre-tax loss in 2004 was primarily due to a $0.4 million negative adjustment from the operator of the pipeline for prior period allocations of income and expenses to the partners. The pre-tax gain in 2003 included a gain of $1.3 million recognized on the sale of a 28-mile portion of Ozark Gas Transmission System’s pipeline located in Oklahoma that had limited strategic value to the overall system. We refer you to Note 7 to the financial statements for additional discussion.

We have severally guaranteed the partnership’s outstanding debt which was $67.0 million at December 31, 2004. Our share of the guarantee equaled $40.2 million. This debt financed a portion of the original construction costs. We advanced $2.1 million to NOARK in 2004 as an adjustment to prior period cash disbursements. No advances to NOARK were required in 2003 and 2002. We refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources-Off-Balance Sheet Arrangements” and Note 11 to the consolidated financial statements for further discussion of our guarantee of NOARK debt.

Other Revenues

In 2004 and 2003, other revenues included gains of $5.8 million and $3.0 million, respectively, related to sales of undeveloped real estate and certain property and equipment. Other revenues for 2004 and 2003 also included pre-tax gains of $4.5 million and $3.1 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense

Interest costs, net of capitalization, were down 2% in 2004 and down 19% in 2003, both as compared to prior years. In 2004, higher interest costs that resulted from increased average borrowings were offset by an increase in capitalized interest in the E&P segment. The decrease in 2003 interest costs compared to 2002 was due to both comparatively lower average borrowings and lower average interest rates. In 2003, our average borrowings decreased as net proceeds of $103.1 million from the sale of our common stock in the first quarter of 2003 were initially used to pay down our revolving credit facility. Interest capitalized increased 56% in 2004 and increased 21% in 2003. Changes in capitalized interest are primarily due to the level of costs excluded from amortization in our E&P segment. These costs increased in 2004 and 2003 due primarily to initial leasehold investments in our Fayetteville Shale play and increased drilling activity.

Income Taxes

Our provision for deferred income taxes was an effective rate of 36.6% in 2004, 36.7% in 2003 and 37.8% in 2002. The changes in the provision for deferred income taxes recorded each year result primarily from the level of taxable income, adjusted for permanent differences.

Pension Expense

We recorded pension expense of $2.2 million in 2004, $3.3 million in 2003 and $0.9 million in 2002. The amount of pension expense recorded by us is determined by actuarial calculations and is also impacted by the funded status of our plans. During 2004, we funded our pension plan with contributions of $1.9 million. At December 31, 2004, our pension plans were underfunded and a liability of $1.5 million was recorded on the balance sheet. As a result of the underfunded status and actuarial data to be completed in early 2005, we expect to record pension expense of $2.0 million to $2.5 million in 2005. For further discussion of our pension plans, we refer you to Note 4 to the financial statements and "Critical Accounting Policies" below.

Adoption of Accounting Principles

In September 2004, the staff of the SEC issued Staff Accounting Bulletin No. 106 (SAB 106) to express the staff's views regarding application of FAS 143, "Accounting for Asset Retirement Obligations," by oil and gas producing companies following the full cost accounting method. SAB 106 addressed the computation of the full cost ceiling test to avoid double-counting asset retirement costs, the disclosures a full cost accounting company is expected to make regarding the impacts of FAS 143, and the amortization of estimated dismantlement and abandonment costs that are expected to result from future development activities. The accounting and disclosures described in SAB 106 have been adopted by the Company as of the third quarter of 2004 and did not have a material impact on the financial position of the Company, or on its results of operations.

Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143), was adopted by the Company on January 1, 2003. FAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The effect of this standard on our results of operations and financial condition at adoption was an increase in current and long-term liabilities of $1.2 million and $5.5 million, respectively; a net increase in property, plant and equipment of $5.3 million; a cumulative effect of adoption expense of $0.9 million and a deferred tax asset of $0.5 million. As of December 31, 2004, we had $0.5 million of current liabilities and $8.1 million of long-term liabilities associated with our asset retirement obligations.

See Note 14 to the consolidated financial statements for the impact of newly issued accounting pronouncements.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds and our unsecured revolving credit facility (discussed below under "Financing Requirements") as our primary sources of liquidity. We may borrow up to $500 million under our new revolving credit facility from time to time. As of March 3, 2005, we had approximately $80 million of indebtedness outstanding under our revolving credit facility. During 2005 we expect to draw on a portion of the funds available under our credit facility to fund our planned capital expenditures (discussed below under "Capital Expenditures"), which are expected to exceed the net cash generated by our operations.

Net cash provided by operating activities was $237.9 million in 2004, compared to $109.1 million in 2003 and $77.6 million in 2002. The primary components of cash generated from operations are net income, depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. Cash from operating activities increased in 2004 and 2003 due primarily to increased net income and the related increases in deferred income taxes generated by our E&P segment. Net cash from operating activities provided 81% of our cash requirements for capital expenditures in 2004, 65% in 2003 and over 84% in 2002.

We believe that our operating cash flow and our credit facility will be adequate to meet our capital, debt repayment and operating requirements for 2005. We fund our day-to-day operating expenses and capital expenditures from operating cash flows, supplemented as needed by borrowings under our credit facility. We may choose to refinance certain portions of these borrowings by issuing long-term debt in the public or private debt markets. We may utilize our existing shelf registration statement or we may file a new shelf registration statement with the SEC in order to facilitate such financings.

Capital Expenditures

Capital expenditures totaled $295.0 million in 2004, $180.2 million in 2003 and $92.1 million in 2002. Capital expenditures for our E&P segment included $3.9 million in 2004, $12.0 million in 2003 and a negative $0.3 million in 2002 related to the change in the amount of accrued expenditures. Additionally, our E&P segment expenditures included acquisitions of interests in natural gas and oil producing properties totaling $14.2 million in 2004, $3.0 million in 2003 and $3.5 million in 2002.

	2004	2003	2002
		(in thousands)	
Exploration and production	$ 281,988	$ 170,886	$ 85,201
Gas distribution	7,298	8,178	6,115
Other	5,704	1,139	746
	$ 294,990	$ 180,203	$ 92,062

Our capital investments for 2005 are planned to be up to $352.7 million, consisting of up to $339.0 million for exploration and production, $10.4 million for gas distribution system improvements and $3.3 million for general purposes. Based on the results achieved to date and assuming that the oil and gas price environment continues to be favorable, we expect to allocate up to $100.2 million of our 2005 E&P capital to our Fayetteville Shale play. We expect that our planned level of capital investments in 2005 will allow us to continue the development of our Overton Field properties in East Texas, continue our conventional drilling in the Arkoma Basin, maintain our present markets, explore and develop other existing gas and oil properties, generate new drilling prospects, and provide for improvements necessary due to normal customer growth in our gas distribution segment. As discussed above, our 2005 capital investment program is expected to be funded through cash flow from operations and our revolving credit facility. We may adjust the level of 2005 capital investments dependent upon our level of cash flow generated from operations and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $325.0 million at December 31, 2004 and $278.8 million at December 31, 2003. The balance at December 31, 2004 includes $125.0 million of notes which are due December 2005. Our intent is to repay the notes using borrowings under our revolving credit facility, however we may seek to re-finance these notes by issuing long-term debt in the public or private markets. In January 2005, we amended and restated our previous $300 million revolving credit facility due to expire in January 2007, increasing the borrowing capacity to $500 million and extending the expiration to January 2010. The amended and restated revolving credit facility replaced the $300 million credit facility and another smaller credit facility. At December 31, 2004, we had $100.0 million of outstanding debt under our prior revolving credit facility. The interest rate on the new facility is calculated based upon our public debt rating and is currently 125 basis points over LIBOR. Our publicly traded notes were downgraded in January 2005 by Standard and Poor's to BBB- from BBB, and continue to be rated Ba2 by Moody's. Any future downgrades in our public debt ratings could increase the cost of funds under our revolving credit facility.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreements, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Additionally, there are certain limitations on the amount of indebtedness that may be incurred by our subsidiaries. We were in compliance with the covenants of our credit agreements at December 31, 2004. Although we do not anticipate debt covenant violations, our ability to comply with our credit agreement is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our credit facility, we would have to decrease our capital expenditure plans.

In 1997, we publicly issued $60.0 million of 7.625% Medium-Term Notes due 2027 and $40.0 million of 7.21% Medium-Term Notes due 2017. In 1995, we publicly issued $125.0 million of 6.7% Notes due in December 2005. In December 2002, we filed a shelf registration statement with the SEC for the purpose of qualifying the potential sale from time to time of up to an aggregate $300 million of equity, debt and other securities. During the first quarter of 2003, we completed the sale of 9,487,500 shares of our common stock under the shelf registration statement. Aggregate net proceeds from the equity offering of $103.1 million were used to repay borrowings under our credit facility.

In June 1998, the NOARK partnership issued $80.0 million of 7.15% Notes due 2018. The notes require semi-annual principal payments of $1.0 million that began in December 1998. We account for our investment in NOARK under the equity method of accounting and do not consolidate the results of NOARK. We and Enogex, the other general partner of NOARK, have severally guaranteed the principal and interest payments on the NOARK debt. Our share of the several guarantee is 60% and amounted to $40.2 million at December 31, 2004. We advanced $2.1 million to NOARK in 2004 as an adjustment to prior period cash disbursements and were not required to advance any funds in 2003 or 2002. If NOARK is unable to generate sufficient cash in the future on a sustainable basis to service its debt and we are continually required to contribute cash to fund our share of the debt service guarantee, we could be required to record our share of the NOARK debt commitment under current accounting rules.

At the end of 2004, our capital structure consisted of 42% debt (excluding our several guarantee of NOARK's obligations) and 58% equity, with a ratio of EBITDA to interest expense of 15.1. EBITDA is a measure required by our debt covenants and is defined as net income plus interest expense, income tax expense, and depreciation, depletion and amortization. Shareholders' equity in the December 31, 2004 balance sheet includes an accumulated other comprehensive loss of $18.8 million related to our hedging activities that is required to be recorded under the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). This amount is based on current market values of our hedges at December 31, 2004, and does not necessarily reflect the value that we will receive or pay when the hedges ultimately are settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our debt covenants as to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 as well as the non-cash impact of any full cost ceiling write-downs, and include the guarantee of NOARK’s obligations. Our capital structure, including our several guarantee of NOARK's obligations of $40.2 million, would be 44% debt and 56% equity at December 31, 2004, without consideration of the accumulated other comprehensive loss related to FAS 133 of $18.8 million. As part of our strategy to insure a certain level of cash flow to fund our operations, we have hedged approximately 70% to 80% of our expected 2005 gas production and 60% to 70% of our expected 2005 oil production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital expenditure plans. If commodity prices remain at or near current levels throughout 2005 and our capital expenditure plans do not change from current expectations, we will increase our long-term debt in 2005. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital expenditures significantly.

We refer you to "Business Overview-Other Items-Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our net income as derived from our audited financial information.

Off-Balance Sheet Arrangements

As discussed above in “Results of Operations-Transportation,” we hold a 25% general partnership interest in NOARK, which owns the Ozark Gas Transmission System that is utilized to transport our gas production and the gas production of others. We account for our investment under the equity method of accounting. We and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018, issued to finance a portion of the original construction costs. Our share of the guarantee is 60% and we are allocated 60% of the interest expense. At December 31, 2004 and 2003, the outstanding principal amount of these notes was $67.0 million and $69.0 million, respectively. Our share of the guarantee was $40.2 million and $41.4 million, respectively. The notes were issued in June 1998 and require semi-annual principal payments of $1.0 million. Under the several guarantee, we are required to fund our share of NOARK's debt service which is not funded by operations of the pipeline. We advanced $2.1 million to NOARK in 2004 as an adjustment to prior period cash disbursements and were not required to advance any funds in 2003 or 2002. We do not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

Our share of the results of operations included in other income (expense) related to our NOARK investment was a pre-tax loss of $0.4 million in 2004, pre-tax income of $1.1 million in 2003 and a pre-tax loss of $0.3 million in 2002. The pre-tax loss in 2004 was primarily due to a $0.4 million negative adjustment from the operator of the pipeline for prior period allocations of income and expenses to the partners. In 2003, our share of pre-tax income included a gain of $1.3 million related to the sale of a 28-mile portion of the pipeline located in Oklahoma. We believe that we will be able to continue to improve the operating results of the NOARK project and expect our investment in NOARK to be realized over the life of the system (see Note 7 of the financial statements for additional discussion).

NOARK's assets and liabilities as of December 31, 2004 and 2003 are as follows:

	2004	2003
	(in thousands)	
Current assets	$ 11,375	$ 20,642
Noncurrent assets	158,149	161,994
	$ 169,524	$ 182,636
Current liabilities	$ 9,610	$ 7,537
Long-term debt	65,000	67,000
Partners' capital	94,914	108,099
	$ 169,524	$ 182,636

NOARK's results of operations for 2004, 2003 and 2002 are summarized below:

	2004	2003	2002
		(in thousands)	
Operating revenues	$ 77,347	$ 72,038	$ 75,959
Pre-tax income	$ 8,756	$ 9,030	$ 3,011

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations at December 31, 2004 were as follows:

Contractual Obligations:

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
			(in thousands)		
Long-term debt	$ 325,000	$ 125,000	$ —	$ 60,000	$ 140,000
Operating leases(1)	10,204	1,691	3,056	2,980	2,477
Unconditional purchase obligations(2)	—	—	—	—	—
Demand charges(3)	103,163	11,613	19,468	20,025	52,057
Other obligations(4)	6,305	6,179	101	25	—
	$ 444,672	$ 144,483	$ 22,625	$ 83,030	$ 194,534

(1) We lease certain office space and equipment under non-cancelable operating leases expiring through 2013.

(2) Our utility segment has volumetric commitments for the purchase of gas under non-cancelable competitive bid packages and non-cancelable wellhead contracts. Volumetric purchase commitments at December 31, 2004 totaled 1.7 Bcf, comprised of 1.4 Bcf in less than one year, 0.2 Bcf in one to three years and 0.1 Bcf in three to five years. Our volumetric purchase commitments are priced primarily at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers.

(3) Our utility segment has commitments for approximately $97.5 million of demand charges on non-cancelable firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers. Our E&P segment has a commitment for approximately $5.7 million of demand transportation charges.

(4) Our other significant contractual obligations include approximately $2.4 million for funding of benefit plans, approximately $0.4 million of land leases, approximately $2.1 million for drilling rig commitments and approximately $1.0 million of various information technology support and data subscription agreements.

We refer you to “Financing Requirements” above for a discussion of the terms of our long-term debt.

Contingent Liabilities and Commitments

We have the following commitments and contingencies that could create, increase or accelerate our liabilities. Substantially all of our employees are covered by defined benefit and postretirement benefit plans. Our return on the assets of these plans in 2002 was negative which, when combined with other factors, resulted in an increase in pension expense and our required funding of the plans for 2004 and 2003. At December 31, 2004, we recorded an accrued pension benefit liability of $1.5 million. As a result of the underfunded status and actuarial data to be completed in early 2005, we expect to record pension expense of $2.0 million to $2.5 million in 2005. See Note 4 to the financial statements and “Critical Accounting Policies” below for additional information.

As discussed above in "Off-Balance Sheet Arrangements," we have guaranteed 60% of the principal and interest payments on NOARK's 7.15% Notes due 2018. At December 31, 2004, the outstanding principal of these notes was $67.0 million. The notes require semi-annual principal payments of $1.0 million. See Note 11 to the financial statements for additional information.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our credit facility described above. We had negative working capital of $2.7 million at the end of 2004 and positive working capital of $5.2 million at the end of 2003. Current assets increased by 31% in 2004 and current liabilities increased 41%. The change in working capital from 2003 to 2004 primarily relates to the increase in our current hedging liability at December 31, 2004.

CRITICAL ACCOUNTING POLICIES

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under the full cost accounting rules of the SEC, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. Unevaluated costs are reviewed twice a year for individual impairment. Capitalized costs within the full cost pool are subjected quarterly to a ceiling test, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent plus the lower of cost or market value of unproved properties. If the net capitalized costs of natural gas and oil properties exceed the ceiling, we will record a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. The write-down may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling.

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Under the SEC's full cost accounting rules, our reserves are required to be priced using prices in effect at the end of the reporting period. Application of these rules during periods of relatively low natural gas or oil prices due to seasonality or other reasons, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on December 31, 2004, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

Natural gas and oil reserves used in the full cost method of accounting cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team in the geographic locations in which the property is located. These estimates are reviewed by senior engineers who are not part of the asset management teams and the executive vice president of our E&P subsidiaries. Finally, the estimates of our proved reserves together with the audit report of Netherland Sewell & Associates, Inc. (discussed below) are reviewed by our Audit Committee. In each of the past three years, revisions to our proved reserve estimates represented no greater than 3% of our total proved reserve estimates, which we believe is indicative of the effectiveness of our internal controls. Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves account for 83% of our total reserve base. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to "The natural gas and oil reserves data we report are only estimates and may prove to be inaccurate." under the heading "Risk Factors" in Item 1 of Part I of this Form 10-K for a more detailed discussion of these uncertainties, risks and other factors.

We engage the services of Netherland Sewell & Associates, Inc., an independent petroleum engineering firm, to audit our reserves as estimated by our reservoir engineers. Netherland, Sewell & Associates, Inc. reports the results of the reserves audit to the Audit Committee of our Board of Directors. In conducting its audit, the engineers and geologists of Netherland, Sewell & Associates study the Company's major properties in detail and independently develop reserve estimates. Minor properties (typically representing less then 20% of the total) are also audited, but less rigorously. For the year-ended December 31, 2004, Netherland, Sewell & Associates issued its audit opinion as to the reasonableness of our reserve estimates, stating that our estimated proved oil and gas reserves are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles.

A decline in gas and oil prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves reported. Our reserve base is 92% natural gas, therefore changes in oil prices used do not have as significant an impact as gas prices on cash flows and reported reserve quantities. Reported discounted cash flows and reserve quantities at December 31, 2004 were $892 million and 645.5 Bcfe. An assumed decrease of $1.00 per Mcf in the December 31, 2004 gas price used to price our reserves would have resulted in an approximate $150 million to $175 million decline in our future cash flows discounted at 10% and an approximate decrease of 10 Bcfe of our reported reserves. Under this assumption, our unamortized costs remained below the ceiling of proved natural gas and oil reserves. The decline in reserve quantities, assuming this decrease in gas price, would have the impact of increasing our unit of production amortization of the full cost pool. The unit of production rate for amortization is adjusted quarterly based on changes in reserve estimates.

Hedging

We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. In recent years, we have hedged 70% to 80% of our annual production. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged.

Our derivative instruments are accounted for under FAS 133 and are recorded at fair value in our financial statements. We have established the fair value of derivative instruments using estimates determined by our counterparties, with such estimates evaluated internally using established index prices and other sources. These valuations are recognized as assets or liabilities in our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production or interest rates, the offset is recorded in other comprehensive income. Results of settled commodity hedging transactions are reflected in natural gas and oil sales or in gas purchases. Results of settled interest rate hedges are reflected in interest expense. Any ineffective hedge, derivative not qualifying for accounting treatment as a hedge, or ineffective portion of a hedge is recognized immediately in earnings. We recorded a loss in revenues of $2.6 million in 2004, a gain of $0.6 million in 2003 and a loss of $1.1 million in 2002 related to the changes in ineffectiveness of our commodity hedges. Future market price volatility could create significant changes to the hedge positions recorded in our financial statements. We refer you to "Quantitative and Qualitative Disclosures about Market Risk" in this Form 10-K for additional information regarding our hedging activities.

Regulated Utility Operations

Our utility operations are subject to the rate regulation and accounting requirements of the APSC. Allocations of costs and revenues to accounting periods for ratemaking and regulatory purposes may differ from those generally applied by non-regulated operations. Such allocations to meet regulatory accounting requirements are considered generally accepted accounting principles for regulated utilities provided that there is a demonstrated ability to recover any deferred costs in future rates.

During the ratemaking process, the regulatory commission may require a utility to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows the utility to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. This causes certain expenses to be deferred as a regulatory asset and amortized to expense as they are recovered through rates. The APSC has not required any unbundling of services, although large industrials are free to contract for their own gas supply. There are no pending regulations relating to unbundling of services; however, should such regulation be proposed and adopted, certain of these assets may no longer meet the criteria for deferred recognition and, accordingly, a write-off of regulatory assets and stranded costs may be required.

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 4 to the financial statements for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2004 benefit obligation and the periodic benefit cost to be recorded in 2005, the discount rate assumed is 6.0% and the expected return assumed is 9.0%. This compares to a discount rate of 6.25% and an expected return of 9.0% used in the prior year.

Using the assumed rates discussed above, we recorded pension expense of $2.2 million in 2004 and $3.3 million in 2003. We reflected a pension liability of $1.5 million at December 31, 2004 and $0.9 million at December 31, 2003. During 2004, we also funded $1.9 million to our pension plans. In 2005, we expect to fund $2.0 million to our pension plans. Assuming a 1% change in the 2004 rates (lower discount rate and lower rate of return), we would have recorded pension expense of $3.3 million in 2004.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 9.3 Bcf at $3.49 per Mcf at December 31, 2004, compared to 10.4 Bcf at $3.33 per Mcf at December 31, 2003.

The gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment's contractual commitments including delivery to customers of our gas distribution business, especially during periods of colder weather. As a result, demand fees paid by the gas distribution segment to the E&P segment, which are passed through to the utility's customers, are a part of the realized price of the gas in storage. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. A significant decline in the future market price of natural gas could result in us writing down our carrying cost of gas in storage.

See further discussion of our significant accounting policies in Note 1 to the financial statements.

FORWARD-LOOKING INFORMATION

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-K identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in commodity prices for natural gas and oil;

- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the extent to which the Fayetteville Shale play can replicate the results of other productive shale gas plays;
- the potential for significant variability in reservoir characteristics of the Fayetteville Shale over such a large acreage position;
- our ability to fund our planned capital expenditures;
- our future property acquisition or divestiture activities;
- the effects of weather and regulation on our gas distribution segment;
- increased competition;
- the impact of federal, state and local government regulation;
- the financial impact of accounting regulations and critical accounting policies;
- changing market conditions and prices (including regional basis differentials);
- the comparative cost of alternative fuels;
- conditions in capital markets and changes in interest rates;
- the availability of oil field personnel, services, drilling rigs and other equipment; and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in this Form 10-K.

Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of natural gas and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risks

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounts for greater than 3% of accounts receivable at December 31, 2004. In addition, please see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

The following table provides information on our financial instruments that are sensitive to changes in interest rates. The table presents our debt obligations, principal cash flows and related weighted-average interest rates by expected maturity dates. Variable average interest rates reflect the rates in effect at December 31, 2004 for borrowings under our credit facility. Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate.

	Expected Maturity Date							Fair Value
	2005	2006	2007	2008	2009	Thereafter	Total	12/31/04
	($ in millions)							
Fixed Rate	$ 125.0	$ —	$ —	$ —	$ 60.0	$ 40.0	$ 225.0	$ 235.4
Average Interest Rate	6.70%	—	—	—	7.63%	7.21%	7.04%	—
Variable Rate	$ —	$ —	$ —	$ —	$ —	$ 100.0	$ 100.0	$ 100.0
Average Interest Rate	—	—	—	—	—	3.66%	3.66%	—

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production, to hedge activity in our marketing segment and to hedge the purchase of gas in our utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which we pay to (production hedge) or receive from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are periodically reviewed to ensure limited credit risk exposure.

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for gas and oil production, gas purchases and marketing volumes. The table presents the notional amount in Bcf and MBbls, the weighted average contract prices and the fair value by expected maturity dates. At December 31, 2004, the fair value of these financial instruments was a $34.5 million liability.

Production and Marketing	Expected Maturity Date 2005	2006
Natural Gas		
Swaps with a fixed-price receipt		
Contract volume (Bcf)	12.9	5.0
Weighted average price per Mcf	$ 5.11	$ 5.89
Fair value (in millions)	$ (15.0)	$ (1.6)
Price collars		
Contract volume (Bcf)	33.4	22.0
Weighted average floor price per Mcf	$ 4.68	$ 4.64
Fair value of floor (in millions)	$ 3.5	$ 5.0
Weighted average ceiling price per Mcf	$ 8.30	$ 8.69
Fair value of ceiling (in millions)	$ (12.3)	$ (8.8)
Swaps with a fixed-price payment		
Contract volume (Bcf)	0.2	—
Weighted average price per Mcf	$ 6.07	$ —
Fair value (in millions)	$ —	$ —
Oil		
Swaps with a fixed-price receipt		
Contract volume (MBbls)	360	120
Weighted average price per Bbl	$ 33.17	$ 37.30
Fair value (in millions)	$ (3.4)	$ (0.4)
Natural Gas Purchases		
Swaps with a fixed-price payment		
Contract volume (Bcf)	2.9	—
Weighted average price per Mcf	$ 6.54	$ —
Fair value (in millions)	$ (1.4)	$ —

At December 31, 2004, the Company had outstanding fixed-price basis differential swaps on 4.1 Bcf of 2005 gas production that did not qualify for hedge accounting treatment. The fair value of these differential swaps was a liability of $0.1 million at December 31, 2004.

At December 31, 2003, the Company had outstanding natural gas price swaps on total notional volumes of 8.0 Bcf at a weighted average price of $4.21 per Mcf in 2004 and 6.0 Bcf at a weighted average price of $4.67 per Mcf in 2005. Outstanding oil price swaps on 426 MBbls were in place that yielded the Company an average price of $28.39 per barrel during 2004. At December 31, 2003, the Company also had outstanding natural gas price swaps on total notional gas purchase volumes of 3.8 Bcf in 2004 for which the Company paid an average fixed price of $5.34 per Mcf.

At December 31, 2003, the Company had collars in place on 23.6 Bcf in 2004 and 1.0 Bcf in 2005 of gas production. The 23.6 Bcf in 2004 had an average floor and ceiling price of $3.85 and $6.48 per Mcf, respectively. The 1.0 Bcf in 2005 had an average floor and ceiling price of $4.50 and $8.00 per Mcf, respectively.

Subsequent to December 31, 2004 and prior to March 3, 2005, we hedged 4.0 Bcf of 2006 gas production under costless collars with floor prices of $5.50 per Mcf and ceiling prices ranging from $7.60 to $13.50 per Mcf.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. We have 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 internal control over financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2004. 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 and procedures may deteriorate.

Our management used the criteria set forth in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to perform its assessment. Based on this assessment, our management, including our Chief Executive Officer and our Chief Financial Officer, concluded, that as of December 31, 2004, our internal control over financial reporting was effective based on those criteria.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report below.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Southwestern Energy Company:

We have completed an integrated audit of Southwestern Energy Company's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Southwestern Energy Company and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted the requirements of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Internal Control over Financial Reporting

Also, in our opinion, management's assessment, included in the accompanying "Management's Report on Internal Control Over Financial Reporting," that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the 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 opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 4, 2005

STATEMENTS OF OPERATIONS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2004	2003	2002
	(in thousands, except share/per share amounts)		
Operating revenues:			
Gas sales	$ 375,460	$ 256,467	$ 198,108
Gas marketing	65,127	43,313	41,709
Oil sales	19,461	14,180	14,340
Gas transportation and other	17,089	13,441	7,345
	477,137	327,401	261,502
Operating costs and expenses:			
Gas purchases - utility	64,311	52,585	48,388
Gas purchases - marketing	60,804	39,428	37,927
Operating expenses	42,157	37,377	38,154
General and administrative expenses	36,074	33,102	26,446
Depreciation, depletion and amortization	73,674	55,948	53,992
Taxes, other than income taxes	17,830	11,619	10,090
	294,850	230,059	214,997
Operating income	182,287	97,342	46,505
Interest expense:			
Interest on long-term debt	18,335	17,722	21,664
Other interest charges	1,461	1,381	1,285
Interest capitalized	(2,804)	(1,792)	(1,483)
	16,992	17,311	21,466
Other income (expense)	(362)	797	(566)
Income before income taxes, minority interest and accounting change	164,933	80,828	24,473
Minority interest in partnership	(1,579)	(2,180)	(1,454)
Income before income taxes and accounting change	163,354	78,648	23,019
Provision for income taxes			
Current	—	—	—
Deferred	59,778	28,896	8,708
	59,778	28,896	8,708
Income before accounting change	103,576	49,752	14,311
Cumulative effect of adoption of accounting principle	—	(855)	—
Net Income	$ 103,576	$ 48,897	$ 14,311
Basic Earnings per share:			
Income before accounting change	$2.90	$1.49	$0.57
Cumulative effect of adoption of accounting principle	—	(0.03)	—
Net Income	$2.90	$1.46	$0.57
Diluted Earnings per share:			
Income before accounting change	$2.80	$1.45	$0.55
Cumulative effect of adoption of accounting principle	—	(0.02)	—
Net Income	$2.80	$1.43	$0.55
Weighted average common shares outstanding:			
Basic	35,725,601	33,396,052	25,226,580
Diluted	36,962,772	34,237,934	26,052,238

The accompanying notes are an integral part of these consolidated financial statements.

BALANCE SHEETS

Southwestern Energy Company and Subsidiaries

	December 31, 2004	December 31, 2003
	(in thousands)	
ASSETS		
Current assets		
Cash	$ 1,235	$ 1,277
Accounts receivable	86,268	58,543
Inventories, at average cost	32,248	31,418
Under-recovered purchased gas costs	—	1,107
Hedging asset - FAS 133	1,205	3,693
Other	10,029	4,272
Total current assets	130,985	100,310
Investments	15,465	13,840
Property, plant and equipment, at cost		
Gas and oil properties, using the full cost method, including $47,239,000 in 2004 and $38,958,000 in 2003 excluded from amortization	1,483,824	1,201,917
Gas distribution systems	207,447	203,793
Gas in underground storage	32,254	33,256
Other	37,820	30,038
	1,761,345	1,469,004
Less: Accumulated depreciation, and amortization	777,189	706,720
	984,156	762,284
Other assets	15,538	14,276
	$ 1,146,144	$ 890,710
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 81,586	$ 54,186
Taxes payable	9,333	5,692
Interest payable	2,334	2,338
Customer deposits	5,903	5,277
Hedging liability - FAS 133	29,886	20,997
Regulatory liability - hedges	—	2,137
Other	4,658	4,441
Total current liabilities	133,700	95,068
Long-term debt	325,000	278,800
Other liabilities		
Deferred income taxes	203,996	147,295
Other	23,912	15,859
	227,908	163,154
Commitments and contingencies		
Minority interest in partnership	11,859	12,127
Shareholders' equity		
Common stock, $0.10 par value; authorized 75,000,000 shares, issued 37,225,584 shares	3,723	3,723
Additional paid-in capital	128,753	123,519
Retained earnings	350,461	246,885
Accumulated other comprehensive income (loss)	(19,816)	(12,520)
Common stock in treasury, at cost, 821,576 shares in 2004 and 1,307,995 shares in 2003	(9,156)	(14,571)
Unamortized cost of restricted shares issued under stock incentive plan, 320,288 shares in 2004 and 421,617 shares in 2003	(6,288)	(5,475)
	447,677	341,561
	$ 1,146,144	$ 890,710

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENTS OF CASH FLOWS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2004	2003	2002
		(in thousands)	
Cash flows from operating activities			
Net income	$ 103,576	$ 48,897	$ 14,311
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	77,350	58,788	56,399
Deferred income taxes	59,778	28,896	8,708
Ineffectiveness of cash flow hedges	2,639	(636)	1,121
Equity in (income) loss of NOARK partnership	433	(1,053)	251
Gain on sale of other property, plant and equipment	(5,802)	(2,991)	—
Minority interest in partnership	(268)	(429)	(1,015)
Cumulative effect of adoption of accounting principle	—	855	—
Change in assets and liabilities:			
Accounts receivable	(27,725)	(16,427)	648
Under/over-recovered gas costs	2,519	(6,804)	(2,487)
Inventories	(2,741)	(6,683)	1,871
Accounts payable	26,052	4,693	(2,883)
Other current assets and liabilities	2,086	1,993	650
Net cash provided by operating activities	237,897	109,099	77,574
Cash flows from investing activities			
Capital expenditures	(291,101)	(168,172)	(92,062)
Sale of natural gas and oil properties	—	—	26,415
Distribution from (investment in) NOARK partnership	(2,059)	2,500	—
Proceeds from the sale of property, plant and equipment	7,121	3,649	—
Increase in gas stored underground	—	(860)	(349)
Other items	591	1,227	1,527
Net cash used in investing activities	(285,448)	(161,656)	(64,469)
Cash flows from financing activities			
Issuance of common stock	—	103,085	—
Payments on revolving long-term debt	(395,100)	(273,000)	(204,100)
Borrowings under revolving long-term debt	441,300	209,400	196,500
Change in bank drafts outstanding	(2,347)	7,988	(9,880)
Proceeds from exercise of common stock options	5,170	4,671	1,955
Debt issuance costs	(1,514)	—	—
Contribution from minority interest owner in partnership	—	—	469
Net cash provided by (used in) financing activities	47,509	52,144	(15,056)
Decrease in cash	(42)	(413)	(1,951)
Cash at beginning of year	1,277	1,690	3,641
Cash at end of year	$ 1,235	$ 1,277	$ 1,690

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

Southwestern Energy Company and Subsidiaries

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Unamortized Restricted Stock Awards	Total
	Shares Issued	Amount						
				(in thousands)				
Balance at December 31, 2001	27,738	$ 2,774	$ 19,764	$ 183,677	$ 5,763	$ (25,196)	$ (3,696)	$ 183,086
Comprehensive income:								
Net income	—	—	—	14,311	—	—	—	14,311
Change in value of derivatives	—	—	—	—	(19,763)	—	—	(19,763)
Change in value of pension liability	—	—	—	—	(3,358)	—	—	(3,358)
Total comprehensive loss	—	—	—	—	—	—	—	(8,810)
Exercise of stock options	—	—	(728)	—	—	2,683	—	1,955
Issuance of restricted stock	—	—	77	—	—	2,601	(2,678)	—
Cancellation of restricted stock	—	—	17	—	—	(69)	52	—
Amortization of restricted stock and other	—	—	—	—	—	—	1,257	1,257
Balance at December 31, 2002	27,738	$ 2,774	$ 19,130	$ 197,988	$ (17,358)	$ (19,981)	$ (5,065)	$ 177,488
Comprehensive income:								
Net income	—	—	—	48,897	—	—	—	48,897
Change in value of derivatives	—	—	—	—	2,027	—	—	2,027
Change in value of pension liability	—	—	—	—	2,811	—	—	2,811
Total comprehensive income	—	—	—	—	—	—	—	53,735
Issuance of common stock	9,488	949	102,136	—	—	—	—	103,085
Exercise of stock options	—	—	1,202	—	—	4,308	—	5,510
Issuance of restricted stock	—	—	1,031	—	—	1,199	(2,230)	—
Cancellation of restricted stock	—	—	10	—	—	(119)	109	—
Amortization of restricted stock and other	—	—	10	—	—	22	1,711	1,743
Balance at December 31, 2003	37,226	$ 3,723	$ 123,519	$ 246,885	$ (12,520)	$ (14,571)	$ (5,475)	$ 341,561
Comprehensive income:								
Net income	—	—	—	103,576	—	—	—	103,576
Change in value of derivatives	—	—	—	—	(6,797)	—	—	(6,797)
Change in value of pension liability	—	—	—	—	(499)	—	—	(499)
Total comprehensive income	—	—	—	—	—	—	—	96,280
Exercise of stock options	—	—	3,078	—	—	4,786	—	7,864
Issuance of restricted stock	—	—	2,166	—	—	665	(2,831)	—
Cancellation of restricted stock	—	—	(10)	—	—	(36)	46	—
Amortization of restricted stock and other	—	—	—	—	—	—	1,972	1,972
Balance at December 31, 2004	37,226	$ 3,723	$ 128,753	$ 350,461	$ (19,816)	$ (9,156)	$ (6,288)	$ 447,677

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

Southwestern Energy Company and Subsidiaries

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the years ended December 31,		
	2004	2003	2002
		(in thousands)	
Balance, beginning of year	$ (12,520)	$ (17,358)	$ 5,763
Current period reclassification to earnings	21,699	24,667	4,735
Current period change in derivative instruments	(28,496)	(22,640)	(24,498)
Current period change in pension liability	(499)	2,811	(3,358)
Balance, end of year	$ (19,816)	$ (12,520)	$ (17,358)

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
December 31, 2004, 2003 and 2002

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Consolidation

Southwestern Energy Company (Southwestern or the Company) is an integrated energy company primarily focused on natural gas. Through its wholly-owned subsidiaries, the Company is engaged in natural gas and oil exploration and production, natural gas gathering, transmission and marketing, and natural gas distribution. Southwestern's exploration and production activities are concentrated in Arkansas, Texas, Louisiana, New Mexico and Oklahoma. The gas distribution segment operates in northern Arkansas and, depending upon weather conditions and current supply contracts, can obtain greater than 50% of its gas supply from one of the Company's exploration and production subsidiaries. The customers of the gas distribution segment consist of residential, commercial and industrial users of natural gas. Southwestern's marketing and transportation business is concentrated in its core areas of operations.

The consolidated financial statements include the accounts of Southwestern Energy Company and its wholly-owned subsidiaries, including Southwestern Energy Production Company (SEPCO), SEECO, Inc., Arkansas Western Gas Company, Southwestern Energy Services Company, Diamond "M" Production Company, Southwestern Energy Pipeline Company, and A.W. Realty Company. The consolidated financial statements also include the results for a limited partnership, Overton Partners, L.P., in which SEPCO is the sole general partner. All significant intercompany accounts and transactions have been eliminated. The Company accounts for its general partnership interest in the NOARK Pipeline System, Limited Partnership (NOARK) using the equity method of accounting. In accordance with Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," the Company recognizes profit on intercompany sales of gas delivered to storage by its utility subsidiary.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Minority Interest in Partnership

In 2001, SEPCO formed a limited partnership, Overton Partners, L.P., with an investor to drill and complete 14 development wells in SEPCO's Overton Field located in Smith County, Texas. Because SEPCO is the sole general partner and owns a majority interest in the partnership, the operating and financial results are consolidated with the Company's exploration and production results and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. SEPCO contributed 50% of the capital required to drill the 14 wells. Revenues and expenses are allocated 65% to SEPCO prior to payout of the investor's initial investment and 85% thereafter. Under the terms of the partnership agreement, the partnership has a maximum life of 50 years. At December 31, 2004 the estimated fair value of the minority ownership position of the partnership does not exceed the minority interest of $11.9 million reflected in the accompanying balance sheet.

Property, Depreciation, Depletion and Amortization

Gas and Oil Properties. The Company follows the full cost method of accounting for the exploration, development, and acquisition of gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits, and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. The Company's unamortized costs of natural gas and oil properties are limited to the sum of the future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. If the Company's unamortized costs in natural gas and oil properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. At December 31, 2004, the Company's net book value of natural gas and oil properties did not exceed the ceiling amount. Decreases in market prices from December 31, 2004 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could result in future ceiling test impairments.

In November 2002, the Company sold oil and gas properties for net proceeds of $26.4 million; the proceeds of the sale were reflected as a reduction of oil and gas properties with no gain or loss recognized.

The Company's adoption of Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" (FAS 143), in January 2003 impacted its accounting for gas and oil properties principally by (1) recognizing future asset retirement obligations as a cost of its oil and gas properties and (2) subjecting to depreciation, depletion and amortization the recorded asset retirement costs as well as estimated future retirement costs associated with future development activities on proved properties, net of salvage value associated with the retirement of the properties.

The adoption of FAS 143, as well as the adoption of Staff Accounting Bulletin No. 106 in September 2004, did not have a material impact upon the Company's calculation of its ceiling test. Additionally, the impact of adoption of FAS 143 did not have a material effect on the Company's financial position or results of operations.

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141), and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142), were issued in June 2001 and became effective for the Company on July 1, 2001, and January 1, 2002, respectively. The Company previously reported that an interpretation of FAS 141 and 142 was being considered as to whether mineral interest use rights in gas and oil properties are intangible assets and would be classified as such, separate from gas and oil properties. In September 2004, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. 142-2 which clarified that the classification and disclosure provisions of FAS 142 are not applicable to drilling and mineral rights of oil and gas producing entities. Therefore, the Company is not required to reclassify or disclose information regarding its oil and gas mineral interests in accordance with FAS 141 and FAS 142.

Gas Distribution Systems. Costs applicable to construction activities, including overhead items, are capitalized. Depreciation and amortization of the gas distribution system is provided using the straight-line method with average annual rates for plant functions ranging from 2.1% to 6.6%.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 7 to 45 years.

The Company charges to maintenance or operations the cost of labor, materials and other expenses incurred in maintaining the operating efficiency of its properties. Betterments are added to property accounts at cost. Retirements are credited to property, plant and equipment at cost and charged to accumulated depreciation, depletion and amortization with no gain or loss recognized, except for abnormal retirements.

Gas in Underground Storage. The Company has two gas storage facilities with the gas in storage stated at average cost, a portion of which is carried as current inventory. The storage facility owned by the gas distribution segment is used for supply to the utility's customers. The cost of the gas withdrawn from this storage facility is passed on to the consumer. The E&P segment primarily uses its storage facility to supplement production in meeting contractual commitments and records revenue on storage withdrawals when such gas is sold. The carrying value of this gas in storage is assessed based on current and future market prices for gas that the Company expects to realize.

Capitalized Interest. Interest is capitalized on the cost of unevaluated gas and oil properties excluded from amortization. In accordance with established utility regulatory practice, an allowance for funds used during construction of major projects is capitalized and amortized over the estimated lives of the related facilities.

Asset Retirement Obligations. As discussed above, FAS 143, "Accounting for Asset Retirement Obligations," was adopted by the Company on January 1, 2003. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Company owns natural gas and oil properties which require expenditures to plug and abandon the wells when reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period the liability is incurred (at the time the wells are drilled or acquired). The effect of this standard on the Company's results of operations and financial condition at adoption was an increase in current and long-term liabilities of $1.2 million and $5.5 million, respectively; a net increase in property, plant and equipment of $5.3 million; a cumulative effect of adoption expense of $0.9 million and a deferred tax asset of $0.5 million. The new standard had no material impact on income before the cumulative effect of adoption in the year ended December 31, 2003, nor would it have had a material impact, on a pro forma basis, in 2002 assuming that this accounting standard had been adopted at such time. The following table summarizes the Company's 2004 and 2003 activity related to asset retirement obligations:

	2004	2003
	(in thousands)	
Asset retirement obligation at January 1	$ 7,544	$ 7,700
Accretion of discount	314	303
Obligations incurred	804	803
Obligations settled	(134)	(852)
Revisions of estimates	37	(410)
Asset retirement obligation at December 31	$ 8,565	$ 7,544
Current liability	473	184
Long-term liability	8,092	7,360
Total asset retirement obligation at December 31	$ 8,565	$ 7,544

Gas Distribution Revenues and Receivables

Customer receivables arise from the sale or transportation of gas by the Company's gas distribution subsidiary. The Company's gas distribution customers are located in northern Arkansas and represent a diversified base of residential, commercial and industrial users. The Company records gas distribution revenues on an accrual basis, as gas volumes are used, to provide a proper matching of revenues with expenses.

The gas distribution subsidiary's rate schedules include purchased gas adjustment clauses whereby the actual cost of purchased gas above or below the projected level included in the rates is permitted to be billed or is required to be credited to customers. Each month, the difference between actual costs of purchased gas and gas costs recovered from customers is deferred. The deferred differences are billed or credited, as appropriate, to customers in subsequent months. Rate schedules include a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The pass-through of gas costs to customers is not affected by this normalization clause.

In the third quarter of 2003, the gas distribution subsidiary received regulatory approval from the Arkansas Public Service Commission (APSC) of a rate increase totaling $4.1 million annually, exclusive of costs to be recovered through the utility's purchase gas adjustment clause. The order also entitled the gas distribution subsidiary to recover certain additional costs totaling $2.3 million through its purchase gas adjustment clause over a two-year period. The gas distribution subsidiary recorded a $1.0 gain in 2003 associated with the future recovery of these costs. The rate increase was effective for all customer bills rendered on or after October 1, 2003.

Gas Production Revenue and Imbalances

The exploration and production subsidiaries record gas sales using the entitlement method. The entitlement method requires revenue recognition of the Company's revenue interest share of gas production from properties in which gas sales are disproportionately allocated to owners because of marketing or other contractual arrangements. At December 31, 2004, the Company had overproduction of 1.3 Bcf valued at $3.7 million and underproduction of 1.5 Bcf valued at $4.4 million. At December 31, 2003, the Company had overproduction of 1.2 Bcf valued at $3.5 million and underproduction of 1.5 Bcf valued at $4.2 million.

Income Taxes

Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes. The Company's net operating loss carryforward at December 31, 2004 was $128.4 million with expiration dates in 2020 through 2024.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage defined commodity price risks and interest rate risks and does not use them for trading purposes. The Company uses commodity swap agreements and options to hedge sales and purchases of natural gas and sales of crude oil. Gains and losses resulting from hedging activities have been recognized in gas and oil sales in the statements of operations when the related physical transactions of commodities were recognized. Changes in fair value of derivative instruments designated as cash flow hedges are reported in other comprehensive income (loss). Gains or losses from commodity swap agreements and options that do not qualify for accounting treatment as hedges are recognized currently as oil and gas sales. See Note 8 for a discussion of the Company's hedging activities and the effects of FAS 133.

Earnings Per Share

Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock. For its diluted earnings per share calculation, the Company had no options outstanding at December 31, 2004, that were not included in the calculation of diluted shares. The Company had options for 222,030 shares of common stock with a weighted average exercise price of $21.93 per share at December 31, 2003, and options for 1,228,744 shares of common stock with a weighted average exercise price of $13.36 per share at December 31, 2002, that were not included in the calculation of diluted shares because they would have had an anti-dilutive effect. The remaining 2,221,128 options at December 31, 2004, with a weighted average exercise price of $12.71, 2,304,880 options at December 31, 2003, with a weighted average exercise price of $9.79, and 1,481,074 options at December 31, 2002, with a weighted average exercise price of $7.53 were included in the calculation of diluted shares. Restricted stock shares included in the calculation of diluted shares were 222,070, 175,364 and 498,123 for 2004, 2003 and 2002, respectively.

Guarantees

The Company follows the disclosure provisions of Financial Accounting Standards Board Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." The nature of the Company's guarantee of debt associated with its investment in NOARK is included in Note 7 and Note 11 to the financial statements. This accounting standard also requires that upon the issuance or modification of guarantees, the guarantor must recognize a liability for the fair value of the obligations it assumes under the guarantee. Liability recognition is required on a prospective basis for guarantees that are made or modified after December 31, 2002.

Accounting for Stock-Based Compensation

At December 31, 2004, the Company has a stock-based employee compensation plan, which is described more fully in Note 9. The Company accounts for this plan under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company does record compensation cost for the amortization of restricted stock shares issued to employees. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (FAS 123), to stock-based employee compensation:

	For the years ended December 31,		
	2004	2003	2002
	(in thousands, except share/per share amounts)		
Net income, as reported	$103,576	$48,897	$ 14,311
Add back: Amortization of restricted stock, net of related tax effects	1,251	1,083	781
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(2,433)	(2,245)	(1,798)
Pro forma net income	$102,394	$ 47,735	$ 13,294
Earnings per share:			
Basic-as reported	$ 2.90	$ 1.46	$ 0.57
Basic-pro forma	2.87	1.43	0.53
Diluted-as reported	2.80	1.43	0.55
Diluted-pro forma	2.77	1.40	0.51

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: no dividend yield for all years; expected volatility of 44.3% for 2004, 47.1% for 2003 and 45.6% for 2002; risk-free interest rate of 3.5% for 2004, 3.7% for 2003 and 3.4% for 2002; and expected lives of 5 to 6 years for all option grants. The fair values of the option grants for each of the years 2004, 2003 and 2002 were $2.6 million, $2.4 million and $1.9 million, respectively.

As discussed further in Note 14 below, “New Accounting Standards,” the Company will adopt the provisions of FAS 123 (Revised 2004) in the third quarter of 2005. This standard will require the recognition of the fair value cost of equity awards, including stock options, as an expense over the service period provided by employees and directors.

(2) DEBT

Debt balances as of December 31, 2004 and 2003 consisted of the following:

	2004	2003
	(in thousands)	
Senior notes:		
6.70% Series due 2005	$ 125,000	$ 125,000
7.625% Series due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Series due 2017	40,000	40,000
	225,000	225,000
Other:		
Variable rate (3.66% at December 31, 2004) unsecured revolving credit arrangements	100,000	53,800
Total long-term debt	$ 325,000	$ 278,800

In January 2005, the Company arranged a new $500 million five-year unsecured revolving credit facility that amended and restated its existing $300 million three-year credit facility that would have expired in January 2007 and replaced a smaller unsecured credit facility that would have matured at the same time. The interest rate on the new credit facility is calculated based upon our debt rating and is currently 125 basis points over LIBOR. The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company’s subsidiaries to incur debt. At December 31, 2004, the Company’s capital structure consisted of 42% debt (excluding its several guarantee of NOARK's obligations) and 58% equity, with a ratio of EBITDA to interest expense of 15.1, and the Company was in compliance with its debt agreements.

The 6.70% senior notes in the table above are due December 2005. The Company currently intends to use its credit facility to repay these notes and, accordingly, these notes are classified as long-term based upon the Company’s ability to fund them on a long-term basis. The 7.625% senior notes are putable at the holders’ option beginning in 2009. Other than these two series of senior notes, there are no other aggregate maturities of long-term debt for each of the years ending December 31, 2005 through 2009. Total interest payments were $18.3 million in 2004, $17.3 million in 2003 and $21.5 million in 2002.

(3) INCOME TAXES

The provision for income taxes included the following components:

	2004	2003	2002
		(in thousands)	
Federal:			
Current	$ —	$ —	$ —
Deferred	55,995	26,507	8,048
State:			
Current	—	—	—
Deferred	3,899	2,506	779
Investment tax credit amortization	(116)	(117)	(119)
Provision for income taxes	$ 59,778	$ 28,896	$ 8,708

The provision for income taxes was an effective rate of 36.6% in 2004, 36.7% in 2003 and 37.8% in 2002. The following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

	2004	2003	2002
		(in thousands)	
Expected provision at federal statutory rate of 35%	$ 57,174	$ 27,527	$ 8,055
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	2,534	1,629	506
Other	70	(260)	147
Provision for income taxes	$ 59,778	$ 28,896	$ 8,708

The components of the Company's net deferred tax liability as of December 31, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$ 241,364	$ 182,081
Stored gas	6,405	6,448
Book over tax basis in partnerships	12,452	12,851
Other	9,164	8,458
	269,385	209,838
Deferred tax assets:		
Accrued compensation	$ 1,566	$ 556
Alternative minimum tax credit carryforward	3,026	3,026
Accrued pension costs	604	318
Cash flow hedges - FAS 133	11,024	7,338
Asset retirement obligations - FAS 143	3,034	2,525
Net operating loss carryforward	46,943	46,456
Other	3,635	3,282
	69,832	63,501
Net deferred tax liability	$ 199,553	$ 146,337

The net deferred tax liability at December 31, 2004 consisted of a current deferred income tax asset of $3.6 million and long-term deferred income tax liabilities of $204.0 million including unamortized deferred investment tax credits of $0.8 million. There were no income tax payments in 2004, 2003 and 2002. The Company's net operating loss carryforward at December 31, 2004, was $128.4 million with expiration dates in 2020 through 2024. The Company also had an alternative minimum tax credit carryforward of $3.0 million and a statutory depletion carryforward of $5.6 million at December 31, 2004.

(4) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (FAS 132). Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets, and funded status as of December 31, 2004 and 2003:

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
		(in thousands)		
Change in benefit obligations:				
Benefit obligation at January 1	$ 60,665	$ 54,694	$ 4,049	$ 3,156
Service cost	2,404	2,170	174	139
Interest cost	3,692	3,659	252	238
Participant contributions	—	—	88	82
Actuarial loss	1,755	3,820	178	668
Benefits paid	(4,716)	(3,678)	(237)	(234)
Benefit obligation at December 31	$ 63,800	$ 60,665	$ 4,504	$ 4,049

	Pension Benefits 2004	Pension Benefits 2003	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003
	(in thousands)			
Change in plan assets:				
Fair value of plan assets at January 1	$ 51,956	$ 41,973	$ 838	$ 732
Actual return on plan assets	4,994	10,659	(21)	(24)
Employer contributions	1,931	3,002	446	282
Participant contributions	—	—	88	82
Benefit payments	(4,716)	(3,678)	(237)	(234)
Amount transferred	—	—	—	—
Fair value of plan assets at December 31	$ 54,165	$ 51,956	$ 1,114	$ 838
Funded status:				
Funded status at December 31	$ (9,635)	$ (8,709)	$ (3,390)	$ (3,211)
Unrecognized net actuarial loss	9,819	8,747	2,030	1,891
Unrecognized prior service cost	3,166	3,610	—	—
Unrecognized transition obligation	—	—	688	774
Net amount recognized	$ 3,350	$ 3,648	$ (672)	$ (546)

The Company uses a December 31 measurement date for all of its plans. Amounts recognized in the balance sheets as of December 31, 2004 and 2003 consist of the following:

	Pension Benefits 2004	Pension Benefits 2003	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003
	(in thousands)			
Accrued pension cost	$ (1,518)	$ (884)	$ (672)	$ (546)
Intangible asset	3,218	3,668	—	—
Accumulated other comprehensive loss (pre-tax)	1,650	864	—	—
Net amount recognized	$ 3,350	$ 3,648	$ (672)	$ (546)

The change in accumulated other comprehensive loss related to the pension plans was income of $0.8 million ($0.5 million after tax) for the year ended December 31, 2004, and income of $4.5 million ($2.8 million after tax) for the year ended December 31, 2003. Included in accumulated other comprehensive loss at December 31, 2004 and 2003 was a $1.6 million loss ($1.0 million net of tax), and a $0.9 million loss ($0.5 million net of tax), respectively, related to the Company's pension plans.

The Company's pension plans have an accumulated benefit obligation in excess of plan assets as of December 31, 2004 and 2003 as follows:

	2004	2003
	(in thousands)	
Projected benefit obligation	$63,800	$60,665
Accumulated benefit obligation	55,683	52,766
Fair value of plan assets	54,165	51,956

Net periodic pension and other postretirement benefit costs include the following components for 2004, 2003 and 2002:

	Pension Benefits 2004	Pension Benefits 2003	Pension Benefits 2002	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
	(in thousands)					
Service cost	$ 2,404	$ 2,171	$ 1,967	$ 174	$ 139	$ 90
Interest cost	3,692	3,659	3,655	252	238	170
Expected return on plan assets	(4,543)	(3,608)	(5,165)	(42)	(36)	(41)
Amortization of transition obligation	—	—	—	86	86	86
Recognized net actuarial loss	233	664	7	102	87	79
Amortization of prior service cost	444	446	457	—	—	—
	$ 2,230	$ 3,332	$ 921	$ 572	$ 514	$ 384

Prior to January 1, 1998, the Company maintained a traditional defined benefit plan with benefits payable based upon average final compensation and years of service. Effective January 1, 1998, the Company amended its pension plan to become a "cash balance" plan on a prospective basis for its non-bargaining employees. A cash balance plan provides benefits based upon a fixed percentage of an employee's annual compensation. The Company's funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plans provide contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages. The Company has established trusts to partially fund its postretirement benefit obligations.

The weighted average assumptions used in the measurement of the Company's benefit obligations at December 31, 2004 and 2003 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
Discount rate	6.00%	6.25%	6.00%	6.25%
Rate of compensation increase	4.00%	4.00%	n/a	n/a

The weighted average assumptions used in the measurement of the Company's net periodic benefit cost for 2004 and 2003 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
Discount rate	6.25%	6.75%	6.25%	6.75%
Expected return on plan assets	9.00%	9.00%	5.00%	5.00%
Rate of compensation increase	4.00%	4.00%	n/a	n/a

The expected return on plan assets for the various benefit plans is based upon a review of the historical returns experienced, combined with the future expected returns based upon the asset allocation strategy employed. The plans seek to achieve an adequate return to fund the obligations in a manner consistent with the federal standards of ERISA and with a prudent level of diversification.

For measurement purposes, the following trend rates were assumed for 2004 and 2003:

	2004	2003
Health care cost trend assumed for next year	10%	11%
Rate to which the cost trend is assumed to decline	5%	5%
Year that the rate reaches the ultimate trend rate	2010	2010

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in thousands)	
Effect on the total service and interest cost components	$ 60	$ (50)
Effect on postretirement benefit obligation	$ 586	$ (492)

The Company’s pension plan weighted-average asset allocations at December 31, 2004, and 2003, by asset category are as follows:

	2004	2003
Asset category:		
Equity securities	65%	65%
Debt securities	33%	33%
Cash equivalents	2%	2%
Total	100%	100%

Assets of the postretirement benefit plans were invested 100% in debt securities for 2004 and 2003.

The investment objective of the benefit plans is to ensure, over the long-term life of the plans, an adequate pool of assets to support the benefit obligations to participants, retirees and beneficiaries. As of December 31, 2004, the defined benefit pension plan had a diversified asset allocation strategy of 60%-70% equity securities and 30%-40% debt (fixed income) securities. Within the equity allocation, the plan invests in small cap, international, large cap growth, large cap value and large cap core securities. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

In 2004, the Company contributed $1.9 million to its pension plans and $0.4 million to its other postretirement benefit plans. The Company expects to contribute $2.0 million to its pension plan and $0.4 million to its other postretirement benefit plans in 2005.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Other Benefits
	(in thousands)	
2005	$ 2,987	$ 188
2006	3,624	183
2007	4,336	199
2008	4,025	238
2009	4,491	275
Years 2010-2014	26,511	1,504

(5) NATURAL GAS AND OIL PRODUCING ACTIVITIES (UNAUDITED)

All of the Company's gas and oil properties are located in the United States. The table below sets forth the results of operations from gas and oil producing activities:

	2004	2003	2002
		(in thousands)	
Sales	$ 286,924	$ 176,245	$ 122,207
Production (lifting) costs	(35,501)	(24,993)	(25,514)
Depreciation, depletion and amortization	(66,924)	(49,553)	(47,680)
	184,499	101,699	49,013
Income tax expense	(67,031)	(37,306)	(18,474)
Results of operations	$ 117,468	$ 64,393	$ 30,539

The results of operations shown above exclude general and administrative expenses and interest costs. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

The table below sets forth capitalized costs incurred in gas and oil property acquisition, exploration and development activities during 2004, 2003 and 2002:

	2004	2003	2002
		(in thousands)	
Proved property acquisition costs	$ 15,384	$ 3,240	$ 3,481
Unproved property acquisition costs	21,830	17,484	4,984
Exploration costs	24,526	20,862	24,552
Development costs	219,455	129,028	51,818
Capitalized costs incurred	$ 281,195	$ 170,614	$ 84,835
Full cost pool amortization per Mcf equivalent	$ 1.20	$ 1.17	$ 1.16

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $2.8 million, $1.8 million and $1.5 million during 2004, 2003 and 2002, respectively, based on the Company's weighted average cost of borrowings used to finance the expenditures.

In addition to capitalized interest, the Company also capitalized internal costs of $14.3 million, $10.6 million and $9.5 million during 2004, 2003 and 2002, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties.

The following table shows the capitalized costs of gas and oil properties and the related accumulated depreciation, depletion and amortization at December 31, 2004 and 2003:

	2004	2003
	(in thousands)	
Proved properties	$ 1,436,585	$ 1,162,959
Unproved properties	47,239	38,958
Total capitalized costs	1,483,824	1,201,917
Less: Accumulated depreciation, depletion and amortization	658,445	593,017
Net capitalized costs	$ 825,379	$ 608,900

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2004. Of the total, approximately $10.5 million represents costs of wells in progress at December 31, 2004, and approximately $25.0 million is related to undeveloped leasehold costs in the Company’s Fayetteville Shale play. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

	2004	2003	2002	Prior	Total
			(in thousands)		
Property acquisition costs	$19,855	$11,361	$ 484	$1,609	$33,309
Exploration and development costs	9,721	34	743	437	10,935
Capitalized interest	864	1,204	198	729	2,995
	$30,440	$12,599	$ 1,425	$2,775	$47,239

(6) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2004, 2003 and 2002:

	2004		2003		2002	
	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	457,016	7,675	374,614	6,784	355,813	7,704
Revisions of previous estimates	(13,832)	199	(16,668)	186	1,110	234
Extensions, discoveries and other additions	196,398	1,274	136,261	1,193	73,803	553
Production	(50,425)	(618)	(37,967)	(531)	(35,972)	(682)
Acquisition of reserves in place	5,634	30	808	48	6,538	15
Disposition of reserves in place	(308)	(52)	(32)	(5)	(26,678)	(1,040)
Proved reserves, end of year	594,483	8,508	457,016	7,675	374,614	6,784
Proved developed reserves:						
Beginning of year	369,867	6,719	286,276	5,633	281,461	6,429
End of year	491,697	7,767	369,867	6,719	286,276	5,633

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves" (standardized measure) is a disclosure required by Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities" (FAS 69). The standardized measure does not purport to present the fair market value of a company's proved gas and oil reserves. In addition, there are uncertainties inherent in estimating quantities of proved reserves. The gas and oil reserve quantities owned by the Company were audited by the independent petroleum engineering firm of Netherland, Sewell & Associates, Inc.

Following is the standardized measure relating to proved gas and oil reserves at December 31, 2004, 2003 and 2002:

	2004	2003 (in thousands)	2002
Future cash inflows	$ 3,857,623	$ 2,914,824	$ 1,951,454
Future production costs	(983,654)	(644,014)	(466,742)
Future development costs	(108,911)	(69,668)	(62,206)
Future income tax expense	(779,386)	(647,605)	(420,336)
Future net cash flows	1,985,672	1,553,537	1,002,170
10% annual discount for estimated timing of cash flows	(1,093,364)	(837,185)	(500,571)
Standardized measure of discounted future net cash flows	$ 892,308	$ 716,352	$ 501,599

Under the standardized measure, future cash inflows were estimated by applying year-end prices, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Year-end market prices used for the standardized measures above were $6.18 per Mcf for gas and $43.45 per barrel for oil in 2004, $5.97 per Mcf for gas and $32.52 per barrel for oil in 2003, and $4.74 per Mcf for gas and $31.20 per barrel for oil in 2002. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the year-end statutory rate, after consideration of permanent differences, to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved gas and oil properties. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the standardized measure.

Following is an analysis of changes in the standardized measure during 2004, 2003 and 2002:

	2004	2003	2002
		(in thousands)	
Standardized measure, beginning of year	$ 716,352	$ 501,599	$ 308,160
Sales and transfers of gas and oil produced, net of production costs	(252,241)	(151,793)	(96,693)
Net changes in prices and production costs	28,009	182,019	284,277
Extensions, discoveries, and other additions, net of future production and development costs	367,892	338,374	137,105
Acquisition of reserves in place	20,771	1,759	11,269
Revisions of previous quantity estimates	(26,481)	(34,637)	4,870
Accretion of discount	99,432	69,413	39,451
Net change in income taxes	(48,091)	(85,441)	(106,177)
Changes in estimated future development costs	(70,005)	(29,399)	(16,533)
Previously estimated development costs incurred during the year	42,143	29,921	16,032
Changes in production rates (timing) and other	14,527	(105,463)	(80,162)
Standardized measure, end of year	$ 892,308	$ 716,352	$ 501,599

(7) INVESTMENT IN UNCONSOLIDATED PARTNERSHIP

The Company holds a 25% general partnership interest in NOARK. NOARK Pipeline was formerly a 258-mile intrastate gas transmission system, which extended across northern Arkansas. In January 1998, the Company entered into an agreement with Enogex Inc. (Enogex) that resulted in the expansion of the NOARK Pipeline and provided the pipeline with access to Oklahoma gas supplies through an integration of NOARK with the Ozark Gas Transmission System (Ozark). Enogex is a subsidiary of OGE Energy Corp. Ozark was a 437-mile interstate pipeline system which began in eastern Oklahoma and terminated in eastern Arkansas. Enogex acquired the Ozark system and contributed it to NOARK. Enogex also acquired the NOARK partnership interests not owned by Southwestern. The acquisition of Ozark and its integration with NOARK Pipeline was approved by the Federal Energy Regulatory Commission in late 1998 at which time NOARK Pipeline was converted to an interstate pipeline and operated in combination with Ozark. The combined pipeline systems are now collectively called the Ozark Gas Transmission System. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK Pipeline, which resulted in the Company's ownership interest in the partnership decreasing to 25% from 48%. The Company is responsible for 60% of debt principal and interest payments in accordance with its several guarantee of NOARK's debt.

The Company's investment in the NOARK partnership totaled $15.4 million at December 31, 2004, and $13.8 million at December 31, 2003. See Note 11 for further discussion of NOARK's funding requirements and the Company's investment in NOARK.

The Company recorded a pre-tax loss of $0.4 million in 2004, pre-tax income of $1.1 million in 2003, and a pre-tax loss of $0.3 million for 2002, for its share of NOARK's results of operations. The pre-tax income in 2003 included a gain of $1.3 million recognized on the sale of a 28-mile portion of Ozark Gas Transmission System located in Oklahoma that had limited strategic value to the overall system. The Company records its share of NOARK's results of operations in other income (expense) on the consolidated statements of operations.

(8) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate the value:

C*ash, Customer Deposits and Short-Term Debt:* The carrying amount is a reasonable estimate of fair value.

Long-Term Debt: The fair value of the Company's long-term debt is estimated based on the expected current rates which would be offered to the Company for debt of the same maturities.

Commodity and Interest Hedges: The fair value of all hedging financial instruments is the amount at which they could be settled, based on quoted market prices or estimates obtained from dealers.

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2004 and 2003 were as follows:

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash	$ 1,235	$ 1,235	$ 1,276	$ 1,276
Customer deposits	$ 5,903	$ 5,903	$ 5,277	$ 5,277
Long-term debt	$ 325,000	$ 335,440	$ 278,800	$ 290,040
Commodity and interest hedges asset (liability)	$ (34,477)	$ (34,477)	$ (17,778)	$ (17,778)

Derivatives and Risk Management

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 137, FAS 138 and FAS 149, was adopted by the Company on January 1, 2001. FAS 133 requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement.

At December 31, 2004, the Company recorded hedging assets of $1.2 million, hedging liabilities of $35.7 million, a regulatory asset of $1.4 million related to its utility gas purchase hedges, and a net of tax loss to other comprehensive income (loss) of $18.8 million. The amount recorded in other comprehensive income (loss) will be relieved over time and taken to the income statement as the physical transactions being hedged occur. At December 31, 2003, the Company recorded hedging assets of $3.7 million, hedging liabilities of $21.5 million, a regulatory liability of $2.1 million related to its utility gas purchase hedges, and a net of tax loss to other comprehensive income (loss) of $12.0 million. The change in accumulated other comprehensive loss related to derivatives was a loss of $10.7 million ($6.8 million after tax) for the year ended December 31, 2004, income of $3.2 million ($2.0 million after tax) for the year ended December 31, 2003, and a loss of $31.9 million ($19.8 million after tax) for the year ended December 31, 2002. Assuming the market prices of futures as of December 31, 2004 remain unchanged, we would expect to transfer a loss of approximately $16.2 million from accumulated other comprehensive income to earnings during the next 12 months when the transactions actually close. All transactions hedged as of December 31, 2004 are expected to mature by December 31, 2006.

The Company recorded a $1.5 million loss in 2004, a $0.5 million loss in 2003 and a $1.1 million loss in 2002 related to basis differential ineffectiveness associated with the Company's cash flow hedges. Additionally, the Company recorded a $1.1 million loss in 2004 and a $1.1 million gain in 2003 related to mark-to-market adjustments on basis differential swaps which did not qualify for hedge treatment. In early 2003, the Company discontinued an interest hedge when it paid down its revolving credit facility with proceeds from an equity issuance. There were no discontinued hedges in 2002. Additional volatility in earnings and other comprehensive income (loss) may occur in the future as a result of the adoption of FAS 133.

The Company uses natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. The Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

The Company uses over-the-counter natural gas and crude oil swap agreements and options to hedge sales of Company production, to hedge activity in its marketing segment and to hedge the purchase of gas in its utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which the Company pays to (production hedge) or receives from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

At December 31, 2004, the Company had outstanding natural gas price swaps on total notional volumes of 12.9 Bcf in 2005 and 5.0 Bcf in 2006 for which the Company will receive fixed prices ranging from $4.49 to $6.89 per MMBtu. Outstanding oil price swaps on 480 MBbls were in place that will yield the Company an average price of $34.20 per barrel. At December 31, 2004, the Company also had outstanding natural gas price swaps on total notional volumes of 3.1 Bcf in 2005 for which the Company will pay an average fixed price of $6.50 per Mcf. At December 31, 2004, the Company had outstanding fixed price basis differential swaps on 4.1 Bcf of 2005 gas production that did not qualify for hedge treatment.

At December 31, 2004, the Company had collars in place on notional volumes of 33.4 Bcf in 2005 and 22.0 Bcf in 2006. The 33.4 Bcf in 2005 had an average floor and ceiling price of $4.68 and $8.30 per MMBtu, respectively. The 22.0 Bcf in 2006 had an average floor and ceiling price of $4.64 and $8.69 per MMBtu, respectively. The Company's price risk management activities reduced revenues by $35.6 million in 2004, $37.4 million in 2003 and $6.1 million in 2002.

The primary market risks related to the Company's derivative contracts are the volatility in commodity prices, basis differentials and interest rates. However these market risks are offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of oil that is hedged, and payment of variable rate interest. Credit risk relates to the risk of loss as a result of non-performance by the Company's counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure the Company has to each counterparty are periodically reviewed to ensure limited credit risk exposure.

(9) STOCK OPTIONS AND RESTRICTED STOCK GRANTS

The Southwestern Energy Company 2004 Stock Incentive Plan (2004 Plan) was adopted in February 2004 and provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2004 Plan replaced the Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan) and the Southwestern Energy Company 2002 Employee Stock Incentive Plan (2002 Plan). The Company also has awards outstanding related to the Southwestern Energy Company 1993 Stock Incentive Plan (1993 Plan) and the Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors (1993 Director Plan). The 2004 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units that in the aggregate do not exceed 2,100,000 shares. The types of incentives which may be awarded are comprehensive and are intended to enable the Board of Directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2004 Plan.

The 2000 Plan provided for the grant of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock that in the aggregate did not exceed 1,250,000 shares. The 2002 Plan provided for the compensation of employees who are not officers or directors of the Company under provisions of Section 16 of the Securities Exchange Act of 1934. The 2002 Plan provided for grants of options, stock appreciation rights, shares of phantom stock and shares of restricted stock that in the aggregate did not exceed 300,000 shares.

The 1993 Plan provided for the compensation of officers and key employees of the Company and its subsidiaries through grants of options, shares of restricted stock, and stock bonuses that in the aggregate did not exceed 1,700,000 shares, the grant of stand-alone stock appreciation rights (SARs), shares of phantom stock and cash awards, the shares related to which in the aggregate did not exceed 1,700,000 shares, and the grant of limited and tandem SARs (all terms as defined in the 1993 Plan). The Company has also awarded stock option grants outside the various stock incentive plans to certain non-officer employees and to certain officers at the time of their hire.

The 2004 Plan does not specify a specific award to the non-employee directors who are eligible to participate in the plan. Previously, the 2000 Plan awarded each non-employee director an annual Director's Option with respect to 8,000 shares of common stock, and the 1993 Director Plan provided for annual stock option grants of 12,000 shares (with 12,000 limited SARs) to each non-employee director.

The following tables summarize stock option activity for the years 2004, 2003 and 2002 and provide information for options outstanding at December 31, 2004:

	2004		2003		2002	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Options outstanding at January 1	2,526,910	$ 10.86	2,709,818	$ 10.17	2,672,186	$ 9.84
Granted	125,010	47.95	222,030	21.93	346,010	11.43
Exercised	429,626	12.07	401,605	12.38	247,464	8.39
Canceled	1,166	12.54	3,333	7.44	60,914	10.09
Options outstanding at December 31	2,221,128	$ 12.71	2,526,910	$ 10.86	2,709,818	$ 10.17

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at Year End	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at Year End	Weighted Average Exercise Price
$6.00 - $7.00	377,883	$ 6.21	4.8	377,883	$ 6.21
$7.01 - $10.00	758,530	7.86	5.7	758,530	7.86
$10.01 - $13.00	560,189	11.72	6.1	429,851	11.83
$13.01 - $18.00	178,000	14.09	1.8	177,167	14.10
$18.01 - $30.00	228,516	21.95	9.0	69,500	21.77
$30.01 - $49.80	118,010	49.46	6.9	—	—
	2,221,128	$ 12.71	5.7	1,812,931	$ 9.60

All options are issued at fair market value at the date of grant and expire seven years from the date of grant for awards under the 2004 Plan and ten years from the date of grant for awards under all other plans. Options generally vest to employees and directors over a three- to four-year period from the date of grant.

As disclosed in Note 1, the Company applies the disclosure-only provisions of FAS 123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans. As discussed further in Note 14 below, “New Accounting Standards,” the Company will adopt the provisions of FAS 123 (Revised 2004) in the third quarter of 2005. This standard will require the recognition of the fair value cost of equity awards as an expense over the service period provided by employees and directors.

The Company granted 59,690 shares, 110,038 shares and 233,460 shares of restricted stock in 2004, 2003 and 2002, respectively. The fair values of the grants were $2.8 million for 2004, $2.3 million for 2003 and $2.7 million for 2002. Of the 1,156,203 shares granted to date, 433,715 shares vest over a three-year period, 679,938 shares vest over a four-year period and the remaining shares vest over a five-year period. The related compensation expense is being amortized over the vesting periods. Compensation expense related to the amortization of restricted stock grants was $2.0 million for 2004, $1.7 million for 2003 and $1.3 million for 2002. As of December 31, 2004, 772,542 shares have vested to employees. Restricted shares cancelled in 2004, 2003 and 2002 were 3,210 shares, 13,142 shares and 6,739 shares, respectively.

(10) COMMON STOCK PURCHASE RIGHTS

In 1999, the Company's Common Share Purchase Rights Plan was amended and extended for an additional ten years. Per the terms of the amended plan, one common share purchase right is attached to each outstanding share of the Company's common stock. Each right entitles the holder to purchase one share of common stock at an exercise price of $40.00, subject to adjustment. These rights will become exercisable in the event that a person or group acquires or commences a tender or exchange offer for 15% or more of the Company's outstanding shares or the Board determines that a holder of 10% or more of the Company's outstanding shares presents a threat to the best interests of the Company. At no time will these rights have any voting power.

If any person or entity actually acquires 15% of the common stock (10% or more if the Board determines such acquiror is adverse), rightholders (other than the 15% or 10% stockholder) will be entitled to buy, at the right's then current exercise price, the Company's common stock with a market value of twice the exercise price. Similarly, if the Company is acquired in a merger or other business combination, each right will entitle its holder to purchase, at the right's then current exercise price, a number of the surviving company's common shares having a market value at that time of twice the right's exercise price.

The rights may be redeemed by the Board for $0.01 per right or exchanged for common shares on a one-for-one basis prior to the time that they become exercisable. In the event, however, that redemption of the rights is considered in connection with a proposed acquisition of the Company, the Board may redeem the rights only on the recommendation of its independent directors (non-management directors who are not affiliated with the proposed acquiror). These rights expire in 2009.

(11) CONTINGENCIES AND COMMITMENTS

The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. The Company's share of the several guarantee is 60%. At December 31, 2004 and 2003, the principal outstanding for these Notes was $67.0 million and $69.0 million, respectively. The Notes were issued in June 1998 and require semi-annual principal payments of $1.0 million. Under the several guarantee, the Company is required to fund its share of NOARK's debt service which is not funded by operations of the pipeline. The Company advanced $2.1 million to NOARK in 2004 and did not advance any funds to NOARK in 2003 or 2002. As a result of the integration of NOARK Pipeline with the Ozark Gas Transmission System, as discussed further in Note 7, management of the Company believes that it will realize its investment in NOARK over the life of the system. Therefore, no provision for any loss has been made in the accompanying financial statements. Additionally, our gas distribution subsidiary has a transportation contract with Ozark Pipeline for 66.9 MMcf per day of firm capacity that expires in 2014.

The Company leases certain office space and equipment under non-cancelable operating leases expiring through 2013. Under certain of these leases the Company is required to pay property taxes, insurance, repairs and other costs related to the leased property. At December 31, 2004, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $1,691,000 in 2005, $1,547,000 in 2006, $1,509,000 in 2007, $1,484,000 in 2008, $1,496,000 in 2009 and $2,477,000 thereafter. Total rent expense for all operating leases was $1,175,000, $1,196,000 and $811,000 in 2004, 2003 and 2002, respectively.

The Company's utility segment has entered into various non-cancelable agreements related to demand charges for the transportation and purchase of natural gas with third parties. These costs are recoverable from the utility's end-use customers. At December 31, 2004, future payments under these non-cancelable demand contracts are $9,687,000 in 2005, $8,566,000 in 2006, $8,815,000 in 2007, $9,202,000 in 2008, $9,588,000 in 2009 and $51,645,000 thereafter. Additionally, the E&P segment has a commitment to a third party for demand transportation charges. At December 31, 2004, future payments under these non-cancelable demand contracts are $1,926,000 in 2005, $1,409,000 in 2006, $677,000 in 2007, $617,000 in 2008, $617,000 in 2009 and $412,000 thereafter.

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

(12) SEGMENT INFORMATION

The Company applies Statement of Financial Accounting Standards No. 131, “Disclosures About Segments of an Enterprise and Related Information” (FAS 131). The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. Revenues for the gas distribution segment arise from the transportation and sale of natural gas at retail. The marketing segment generates revenue through the marketing of both Company and third-party produced gas volumes.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes and the cumulative effect of adoption of accounting principle is the sum of operating income, interest expense, other income (expense) and minority interest in partnership. The "Other" column includes items not related to the Company's reportable segments including real estate, pipeline operations and corporate items.

	Exploration And Production	Gas Distribution	Marketing (in thousands)	Other	Total
2004					
Revenues from external customers	$ 253,920	$ 152,288	$ 65,128	$ 5,801	$ 477,137
Intersegment revenues	33,004	161	249,849	448	283,462
Operating income	164,585	8,516	3,151	6,035	182,287
Depreciation, depletion and amortization expense	66,924	6,592	67	91	73,674
Interest expense(1)	11,537	4,461	—	994	16,992
Provision for income taxes(1)	55,197	1,471	1,151	1,959	59,778
Assets	890,486	184,213	29,243	42,202(2)	1,146,144
Capital expenditures(3)	281,988	7,298	—	5,704	294,990
2003					
Revenues from external customers	$ 143,864	$ 137,200	$ 43,313	$ 3,024	$ 327,401
Intersegment revenues	32,381	156	158,664	448	191,649
Operating income	84,737	6,766	2,612	3,227	97,342
Depreciation, depletion and amortization expense	49,553	6,252	50	93	55,948
Interest expense(1)	11,911	4,395	—	1,005	17,311
Provision for income taxes(1)	26,010	767	954	1,165	28,896
Assets	666,815	171,027	16,223	36,645(2)	890,710
Capital expenditures(3)	170,886	8,178	10	1,129	180,203
2002					
Revenues from external customers	$ 104,081	$115,712	$41,709	$ —	$ 261,502
Intersegment revenues	18,126	138	89,357	448	108,069
Operating income	36,048	7,563	2,652	242	46,505
Depreciation, depletion and amortization expense	47,680	6,115	104	93	53,992
Interest expense(1)	16,597	3,868	—	1,001	21,466
Provision (benefit) for income taxes(1)	6,744	1,316	963	(315)	8,708
Assets	527,591	163,803	9,998	38,770(2)	740,162
Capital expenditures	85,201(4)	6,115	—	746	92,062

(1) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as debt and income tax expense (benefit) are incurred at the corporate level.

(2) Other assets include the Company's equity investment in the operations of NOARK (see Note 7), corporate assets not allocated to segments and assets for non-reportable segments.

(3) Capital expenditures for 2004 and 2003 included $3.9 million and $12.0 million, respectively, related to the change in accrued expenditures between years.

(4) Includes $0.5 million in 2002 funded by the owner of the minority interest in Overton partnership.

Included in intersegment revenues of the marketing segment are $235.7 million, $154.1 million and $89.4 million for 2004, 2003 and 2002, respectively, for marketing of the Company’s exploration and production sales. Intersegment sales by the E&P segment and marketing segment to the gas distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures, prepaid debt costs, and prepaid and intangible pension related costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

(13) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2004 and 2003:

	Mar 31	June 30	Sept 30	Dec 31
	(in thousands, except per share amounts)			
	2004			
Operating revenues	$ 119,790	$ 96,427	$ 111,395	$ 149,525
Operating income	43,307	38,246	45,437	55,297
Net income	24,472	20,790	25,399	32,915
Basic earnings per share	0.69	0.58	0.71	0.92
Diluted earnings per share	0.67	0.56	0.68	0.88
	2003			
Operating revenues	$ 98,655	$ 66,487	$ 71,068	$ 91,191
Operating income	27,674	19,946	22,707	27,015
Net income	13,642	9,526	10,878	14,851
Basic earnings per share	0.48	0.27	0.31	0.42
Diluted earnings per share	0.47	0.26	0.30	0.41

(14) NEW ACCOUNTING STANDARDS

In December 2004, the FASB issued Statement on Financial Accounting Standards No. 123 (Revised 2004), “Share-Based Payment,” revising FASB Statement 123, “Accounting for Stock-Based Compensation” and superseding APB Opinion No. 25, “Accounting for Stock Issued to Employees.” This statement requires a public entity to measure the cost of services provided by employees and directors received in exchange for an award of equity instruments, including stock options, at a grant-date fair value. The fair value cost is then recognized over the period that services are provided. FAS 123 (Revised 2004) is effective for interim and annual periods that begin after June 15, 2005 and will be adopted by the Company in the third quarter of 2005. See Note 1 of these financial statements for a disclosure of the effect on net income and earnings per share for the years 2002 through 2004 if the Company had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

The FASB issued Statement on Financial Accounting Standards No. 153, “Exchanges of Productive Assets,” in December 2004 that amended APB Opinion No. 29, “Accounting for Nonmonetary Transactions.” FAS 153 requires that nonmonetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The Company does not expect this statement to have a material impact on it results of operations or its financial condition.

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, “Inventory Costs, an amendment of ARB No. 43, Chapter 4,” which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. The Company has not determined the impact, if any, that this statement will have on its results of operations or its financial condition.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

We have 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, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, summarize and report the information that is required to be disclosed or submitted by us within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of December 31, 2004. There were no significant changes in our internal control over financial reporting during the three months ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 52 of this Form 10-K.

ITEM 9B. OTHER INFORMATION

There was no information required to be disclosed in a report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2004 that was not reported on such form.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The definitive Proxy Statement to holders of our common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 11, 2005, or the 2005 Proxy Statement, is hereby incorporated by reference for the purpose of providing information about the identification of our directors, and for discussion of our audit committee financial expert. We refer you to the sections "Election of Directors" and "Share Ownership of Management, Directors and Nominees" in the 2005 Proxy Statement for information concerning our directors. We refer you to the section "Meetings and Committees of the Board of Directors" for discussion of our audit committee financial expert. Information concerning our executive officers is presented in Part I, Item 4 of this Form 10-K. We refer you to the section "Section 16(a), Beneficial Ownership Reporting Compliance" for information relating to compliance with Section 16(a) of the Exchange Act.

The Company has adopted a code of ethics that applies to the Company's chief executive officer, chief financial officer and chief accounting officer. The full text of such code of ethics has been posted on the Company's website at www.swn.com, and is available free of charge in print to any shareholder who requests it. Requests for copies should be addressed to the Secretary at 2350 N. Sam Houston Parkway East, Suite 300, Houston TX, 77032.

ITEM 11. EXECUTIVE COMPENSATION

The 2005 Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation. We refer you to the section "Executive Compensation" in the 2005 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The 2005 Proxy Statement is hereby incorporated by reference for the purpose of providing information about securities authorized for issuance under our equity compensation plans and security ownership of certain beneficial owners and our management. For information about our equity compensation plans, refer to "Equity Compensation Plans" in our 2005 Proxy Statement. Refer to the sections "Security Ownership of Certain Beneficial Owners" and "Share Ownership of Management, Directors and Nominees" for information about security ownership of certain beneficial owners and our management.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The 2005 Proxy Statement is hereby incorporated by reference for the purpose of providing information about certain relationships and related transactions. Refer to the sections "Certain Transactions," "Share Ownership of Management, Directors and Nominees," "Agreements Concerning Employment and Change in Control," "Pension Plans" and "Equity Compensation Plans" for information about transactions with our executive officers, directors or management.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The 2005 Proxy Statement is hereby incorporated by reference for the purpose of providing information about fees paid to the principal accountant and the audit committee's pre-approval policies and procedures. We refer you to the section "Relationship with Independent Registered Public Accounting Firm" for information concerning fees paid to our principal accountant and the audit committee's pre-approval policies and procedures and other required information.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) The consolidated financial statements of Southwestern Energy Company and its subsidiaries and the report of independent auditors are included in Item 8 of this Form 10-K.

(2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.

(3) The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused the report to be signed on its behalf by the undersigned, thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY

Dated: March 8, 2005

BY: /s/ Greg D. Kerley
Greg D. Kerley
Executive Vice President
and Chief Financial 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 March 8, 2005.

/s/ Harold M. Korell Harold M. Korell	Director, Chairman, President and Chief Executive Officer
/s/ Greg D. Kerley Greg D. Kerley	Executive Vice President and Chief Financial Officer
/s/ Stanley T. Wilson Stanley T. Wilson	Controller and Chief Accounting Officer
/s/ Lewis E. Epley, Jr Lewis E. Epley, Jr	Director
/s/ John Paul Hammerschmidt John Paul Hammerschmidt	Director
/s/ Robert L. Howard Robert L. Howard	Director
/s/ Vello A. Kuuskraa Vello A. Kuuskraa	Director
/s/ Kenneth R. Mourton Kenneth R. Mourton	Director
/s/ Charles E. Scharlau Charles E. Scharlau	Director

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated By-Laws of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant's Annual Report filed on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2002)
3.2	Amended and Restated Articles of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 4.2 to the Registrant's Registration Statement on Form S-3 (File No. 333-101658) filed on December 5, 2002)
4.1	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.1 to the Registrant's Form S-3 (File No. 333-101658)
4.2	Amended and Restated Rights Agreement between Southwestern Energy Company and the First Chicago Trust Company of New York dated April 12, 1999. (Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1999)
4.3	Amendment No. 1 to the Amended and Restated Rights Agreement between Southwestern Energy Company and Equiserve Trust Company as successor to the First Chicago Trust Company of New York dated March 15, 2002. (Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2001)
4.4	Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago (now Bank One Trust Company, N.A.). (Incorporated by reference to Exhibit 4 to Amendment No. 1 to Registrant's Registration Statement on Form S-3 (File No. 33-63895) filed on November 17, 1995)
4.5*	Amended and Restated Credit Agreement dated January 4, 2005 among Southwestern Energy Company, JPMorgan Chase Bank, NA, SunTrust Bank, Royal Bank of Scotland, Royal Bank of Canada, Fleet National Bank, and the other lenders named therein, JPMorgan Chase Bank, NA, as administrative agent, SunTrust Bank as syndication agent.
10.1	Consulting Agreement between Southwestern Energy Company and Charles E. Scharlau, dated May 15, 2002. (Incorporated by reference to Exhibit 3.1 to Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2002)
10.2	Form of Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.20 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1991)
10.3	Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.4	Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.2(b) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.5	Southwestern Energy Company Supplemental Retirement Plan amended as of February 1, 1996. (Incorporated by reference to Exhibit 10.5 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1995)
10.6	Southwestern Energy Company Supplemental Retirement Plan Trust, dated December 30, 1993. (Incorporated by reference to Exhibit 10.6 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1993)
10.7	Southwestern Energy Company Non-Qualified Retirement Plan, effective October 4, 1995. (Incorporated by reference to Exhibit 10.7 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1995)

10.8	Amended and Restated Limited Partnership Agreement of NOARK Pipeline System, Limited Partnership dated January 12, 1998. (Incorporated by reference to Exhibit 10.7 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1997)
10.9	Amendment No. 1 to the Amended and Restated Limited Partnership Agreement of NOARK Pipeline System, Limited Partnership dated June 18, 1998. (Incorporated by reference to Exhibit 10.14 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.10	Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993. (Incorporated by reference to Exhibit 10.4(e) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1993)
10.11	Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors, dated April 7, 1993. (Incorporated by reference to Exhibit 10.4(f) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1993)
10.12	Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2000 Annual Meeting of Shareholders)
10.13	Southwestern Energy Company 2002 Employee Stock Incentive Plan, effective October 23, 2002. (Incorporated by reference to Exhibit 3.1 to Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2002)
10.14	Southwestern Energy Company 2002 Performance Unit Plan, effective December 11, 2002. (Incorporated by reference to Exhibit 3.1 to Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2002)
10.15	Southwestern Energy Company 2004 Stock Incentive Plan. (Incorporated by reference to Appendix A to the Company's Proxy Statement dated March 29, 2004)
10.16	Form of Incentive Stock Option Agreement. (Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on December 20, 2004)
10.17	Form of Restricted Stock Agreement. (Incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed on December 20, 2004)
10.18	Form of Non-Qualified Stock Option Agreement for non-employee directors. (Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on December 20, 2004)
10.19*	Form of Non-Qualified Stock Option Agreement.
10.20	Description of Compensation Payable to Non-Management Directors. (Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 2, 2005)
21.1*	List of Subsidiaries.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith