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

Form 10-K

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

For the fiscal year ended December 31, 2003

Commission file number 1-8246

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 number of shares outstanding as of February 23, 2004, of the Registrant's Common Stock, par value $0.10, was 35,957,889. The aggregate market value of the voting stock held by non-affiliates of the Registrant was $525,004,005 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2003, of $15.01. For purposes of this calculation, the Registrant has assumed that its directors and executive officers are affiliates.

Document incorporated by reference: Portions of the Registrant's Definitive Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 12, 2004 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, 2003

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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 our most important committees (including our Audit, Compensation and Nominating Committees) 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 for and production of natural gas. Celebrating our 75th anniversary in 2004, we were originally organized in 1929 in Arkansas 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 crude 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), and Diamond "M" Production Company. SEECO operates exclusively in Arkansas, holds a large base of both developed and undeveloped gas reserves and conducts an ongoing drilling program in the historically productive Arkansas part of the Arkoma Basin. SEPCO conducts development drilling and exploration programs in the Oklahoma portion of 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. A wholly-owned subsidiary of SEPCO, Overton Partners, L.L.C., 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 142,000 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 and transportation services in 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 Business Strategy

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 adding 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.

For our E&P business, the key elements of our 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 our properties that have substantial 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.

- *Grow Through Exploration*. We conduct an active exploration program that is designed to complement our lower-risk exploitation and development drilling efforts with moderate to high-risk exploration projects that have greater reserve potential. We employ a rigorous prospect selection process utilizing state-of-the-art computer-aided exploration technology to analyze and interpret geological and geophysical data, including a large inventory of 3-D seismic data.

We intend to manage our exploration expenditures through the optimal scheduling of our drilling program and by selectively reducing our participation in certain exploratory prospects through promoted sales of interests to industry partners.

- *Pursue Strategic Acquisitions*. 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 exploration and exploitation potential.

- *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.

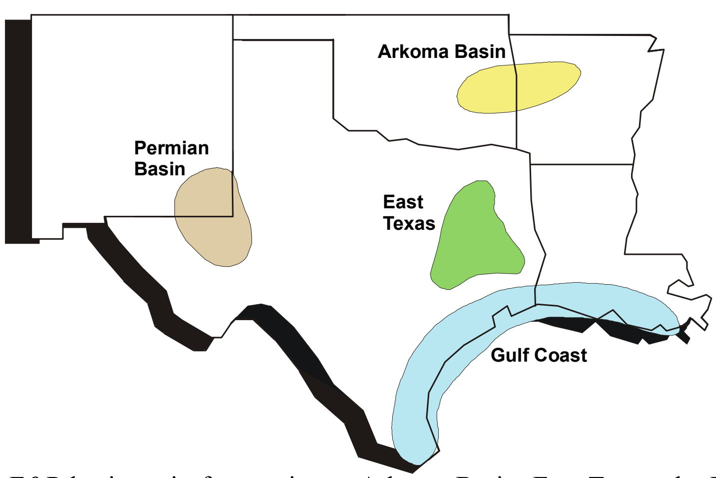
Recent Developments

Improved Liquidity. In January 2004, we entered into a new $300 million three-year unsecured revolving credit facility with a group of banks which replaced our previous $125 million credit facility that was due to expire in July 2004. We also have access to an additional $15 million of borrowing capacity under a separate unsecured credit facility that also expires in January 2007. As of February 23, 2004, we had $265.9 million of available capacity under our revolving credit facilities.

Utility Rate Increase. 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 in 2003 included a gain of $1.0 million related to the recovery of these costs. The rate increase was effective on October 1, 2003.

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 which has implemented a number of initiatives to refocus our E&P business. These efforts have included a recruiting campaign to improve our technical professional staff which has resulted in a change in that staff of more than 75%. Our explorationists now have an average of over 20 years of experience and have a proven track record of finding natural gas and oil during their careers. The operations of our E&P business were reorganized into asset management teams based on the geographic location of our exploration and development projects. In addition, a new incentive compensation plan, which includes stock-based awards, was established for our asset management teams to more closely align our employees' efforts with the interests of our shareholders.



Areas of Operation

We operate our E&P business in four regions—Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. Operating income for our E&P business was $84.7 million and EBITDA was $132.0 million in 2003. 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 increased 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 table that reconciles EBITDA with our net income as derived from our audited financial information.

As of December 31, 2003, our estimated proved natural gas and oil reserves were 503.1 Bcfe and had a pre-tax PV-10 value of $994.3 million and an after-tax PV-10 value, or standardized measure, of $716.4 million. Refer to footnote 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 91% of our proved reserves were natural gas and 82% were classified as proved developed. We operate approximately 77% of our reserves, based on our PV-10 value, and our average proved reserves-to-production ratio, or average reserve life, approximated 12.2 years at year-end 2003. Revenues of our E&P subsidiaries are predominantly generated from production of natural gas. Sales of natural gas production accounted for 91% of total operating revenues for this segment in 2003, 88% in 2002, and 89% in 2001.

In 2003, we replaced 351% of our production volumes by adding an estimated 144.5 Bcfe of proved natural gas and oil reserves at a finding and development cost of $1.18 per Mcfe, excluding reserve revisions. Our finding and development cost, including the effect of downward reserve revisions that were primarily due to poorer-than-expected well performance related to our South Louisiana properties, was $1.33 per Mcfe in 2003. Our finding and development costs fluctuate depending on the success of our drilling program each year, and can also be impacted by our acquisition of undeveloped properties. For the three years ended December 31, 2003, we achieved an average reserve replacement ratio of 262% and an average finding and development cost of $1.12 per Mcfe, excluding reserve revisions. Including reserve revisions, these three-year averages were 229% and $1.28 per Mcfe, respectively.

Our portfolio includes low-risk development drilling in the Arkoma Basin and East Texas, moderate-risk exploration and exploitation properties in the Permian Basin, and higher risk, high-potential exploration opportunities in the onshore Gulf Coast region. Additionally, during 2003 we acquired 345,310 net undeveloped leasehold acres for approximately $11.0 million that we expect to be part of our future development efforts. We are evaluating potential projects for this acreage which more than doubled our total undeveloped acreage position at December 31, 2002. The following table provides information as of December 31, 2003 related to proved reserves, well count, and net acreage, and 2003 annual information as to production and capital expenditures, for each of our core operating areas and overall:

	Arkoma	East Texas	Permian	Gulf Coast	New Ventures	Total
Estimated Proved Reserves:						
Total Reserves (Bcfe)	211.7	196.3	55.6	39.5	-	503.1
Percent of Total	42%	39%	11%	8%	-	100%
Percent Natural Gas	100%	96%	42%	85%	-	91%
Percent Proved Developed	84%	78%	82%	83%	-	82%
Production (Bcfe)	18.9	13.6	4.2	4.5	-	41.2
Capital Investments (millions)	$32.9	$97.3	$9.3	$20.4	$11.0	$170.9
Total Gross Wells	842	109	393	70	-	1,414
Total Net Acreage	256,362	25,456	41,564	33,349	345,310	702,041
Net Undeveloped Acreage	91,683	11,050	16,182	21,540	345,310	485,765
PV-10:						
Pre-tax (millions)	$464.9	$335.6	$101.9	$91.9	-	$994.3
After-tax (millions)	$335.0	$241.8	$73.4	$66.2	-	$716.4
Percent of Total	47%	34%	10%	9%	-	100%
Percent Operated	80%	95%	30%	52%	-	77%

Arkoma Basin. The Arkoma Basin continues to provide a solid foundation for our E&P program and represents a significant source of our production and reserves. At December 31, 2003, we had approximately 211.7 Bcf of natural gas reserves in the Arkoma Basin, representing approximately 42% of our total reserves. During 2003, we participated in 60 wells and 63 workovers which added 28.8 Bcf of gas reserves at a finding and development cost of $1.14 per Mcf, excluding revisions. Our gas production in the Arkoma Basin was 18.9 Bcf during 2003, or 51.8 MMcf per day.

Our activities in the Arkoma Basin continue to generate a significant amount of our cash flow. With three-year average finding and development costs of $1.14 per Mcf, excluding revisions, and three-year average production, or lifting, costs of $0.38 per Mcf (including production taxes), our cash margins in the Arkoma Basin are very attractive. Lifting costs continued to be low during 2003 at $0.46 per Mcf (including production taxes). After direct general and administrative expenses and cash expenses, we realized 87% of the average price received in the Arkoma Basin, excluding the impact of commodity hedges.

Gas production from wells in the Arkoma Basin typically declines at a hyperbolic rate, then production will flatten and remain fairly constant at a lower sustained rate for several years. For example, the Grimmer #1-17 well in Johnson County, Arkansas, was production tested in April 2002 at a gross production rate of 10.7 MMcf per day. Through December 31, 2003, that well had cumulative gross production of 1.1 Bcf and is currently producing at a rate of 600 Mcf per day.

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." 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 2003, we completed 16 wells out of 22 drilled in the fairway and those wells added 8.1 Bcf of new natural gas reserves. Our average working interest in the 2003 fairway wells drilled is 46% and our average net revenue interest is 40%. We intend to drill up to 18 wells and perform 34 workovers in the fairway portion of the Arkoma Basin in 2004.

In recent years, we have extended our development program into the Oklahoma portion of the Arkoma Basin, and in 2003 we continued to have good success in our Haileyville prospect area in Pittsburg County, Oklahoma. One well of particular note, the Collins #2-13, encountered 43 feet of net pay in the Dirty Creek sand and is currently producing at a rate of 7.3 MMcf per day. In 2004, we plan to drill 7 additional wells in the Haileyville area.

We also significantly increased our drilling activity during 2003 in our Ranger Anticline prospect area, located at the southern edge of the Arkansas portion of the basin. Since drilling our first successful well at Ranger in 1997, we have developed a better understanding of the complex faulting and highly-fractured nature of this play. By the end of 2002, we had successfully drilled 13 out of 16 wells at Ranger when we received regulatory approval to downspace the field to 80-acre spacing. Previously, development of the field was based upon 640-acre spacing. Act 964 was passed by the Arkansas legislature in March 2003 and provided operators in Arkansas the ability to pursue multi-well development of original 640-acre units, applied for on a field-by-field basis, where it is supported by technical data. As a result, we significantly increased our drilling activity in 2003 and successfully drilled 10 out of 12 wells at Ranger, adding 13.1 Bcf of reserves at a finding cost of $0.85 per Mcf. From our first well drilled in 1997 through the end of 2003, we have drilled a total of 23 successful wells out of 28 attempts, adding 30.2 net Bcf of reserves at a finding cost of $0.70 per Mcf. 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 typically cost approximately $800,000 to $1.2 million to drill and complete, have average initial production rates of 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 23 successful wells drilled through December 31, 2003 is 78% and our average net revenue interest is 62%.

Not only did the approved downspacing provide a new level of development activity at Ranger, but our growing understanding of the geology indicated that the productive area could be much bigger than once thought. During 2003, we increased our acreage position at Ranger to approximately 4,400 gross developed acres and 37,100 gross undeveloped acres at December 31, 2003. Currently, our average working interest in our gross undeveloped acreage position at Ranger is 65%. In February 2004, we production tested the Smith #1-10 well at 2.7 MMcf per day. This exploratory test well in which we hold a 100% working interest is located six miles west of our existing Ranger production, and indicates that the gas-filled Borum sands could stretch over a significantly larger area. Also, in February 2004, we drilled the Doggle #2-15 and logged over 350 feet of pay in the well. This exploratory well is located one mile south of the Smith well in Logan County, Arkansas. We are currently preparing to production test this well in which we hold a 100% working interest. We expect these wells to be brought on-line in the second quarter of 2004 upon completion of a 6-mile pipeline. We are currently drilling a third exploratory well in the area, the Albright #1-7, and are seeing encouraging results. The Albright #1-7 well is located east of the Smith and Doggle wells and approximately three miles west of our existing Ranger production. We believe that Ranger may hold significant development potential and we intend to drill up to 20 wells in this area in 2004.

Additionally in 2003, we performed 63 workover projects in the Arkoma Basin which included fracture stimulations, artificial lift, recompletion and wellbore repair projects, resulting in net production increases totaling 2.5 MMcf per day at a total net cost of $5.3 million. One workover project of note was the recompletion of the George #1-11 well to the Jenkins sand. This workover project added net proved reserves of 459 MMcf and increased production by 450 Mcf per day for a total cost of $84,000.

Our strategy for the Arkoma Basin is to continue our development drilling and workover programs at a level that maintains our production and reserve base. In 2004, we plan to invest approximately $44.3 million in the Arkoma Basin to drill over 80 wells and perform approximately 95 workover projects.

East Texas. The Overton Field in Smith County, Texas, 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 level of infill drilling that is possible in the field over the next several years. Our interest in the Overton Field (which now totals approximately 17,900 gross acres) was originally acquired in April 2000 and 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. We are seeking regulatory approval to allow downspacing of the Overton Field to optional 40-acre spacing in 2004, which will help facilitate the development of our extensive inventory of additional drilling locations. Our average working interest in the Overton Field is 95% and our average net revenue interest is 76%.

We expanded our position in the area during 2001 through a farm-in of approximately 5,800 adjacent acres. This acreage, which we call "South Overton," contains nine 640-acre units, most of which have only been drilled to 320-acre spacing. In 2003, this area was expanded by an additional 700 acres. We have two farm-in agreements that require us to drill a minimum of one well per 90 days and one well per 120 days, respectively, on this acreage in 2004. Our current net revenue interest in South Overton is 73%.

In 2001, SEPCO formed a limited partnership with an investor to drill and complete 14 development wells in the Overton Field. All 14 development wells have been completed and we have no continuing obligations to drill additional wells. Because SEPCO is the sole general partner and owns a majority interest in the partnership, operating and financial results for the partnership are consolidated with our other operations and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. During 2002 and 2001, the minority interest owner in the partnership contributed $0.5 million and $13.5 million, respectively, in capital to the limited partnership. The investor's share of 2003, 2002 and 2001 revenues, less operating costs and expenses, was $2.2 million, $1.5 million and $0.9 million, respectively.

In 2003, we drilled and completed a total of 57 wells, compared to 18 wells drilled in 2002 and 15 wells drilled during 2001. At December 31, 2003, six wells were in various stages of drilling. 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 60.1 MMcfe at year-end 2003 resulting in net production of 13.6 Bcfe during 2003. Initial production rates of new wells drilled in the field during 2003 averaged 3.3 MMcfe per day. Our average production costs (including production taxes) were $0.45 per Mcfe in 2003, compared to $0.40 per Mcfe in 2002 and $0.70 per Mcfe in 2001.

Our proved reserves at the Overton Field increased to 196.3 Bcfe at year-end 2003, or 39% of our total reserves. We invested approximately $97.3 million at the Overton Field during 2003 which resulted in proved reserve additions of 102.6 Bcfe at a finding and development cost of $0.95 per Mcfe, excluding revisions, compared to $0.60 per Mcfe in 2002. 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. Our three-year average finding cost at Overton is $0.82 per Mcfe, excluding revisions. The average estimated ultimate recovery of gas and oil reserves from new wells completed in 2003 was approximately 2.2 gross Bcfe per well.

In 2004, we plan to invest approximately $105.5 million at Overton and drill 70 wells in the field utilizing at least five drilling rigs, with some locations likely being 40-acre spaced wells. Although current field rules at Overton allow for development at optional 80-acre spacing (eight wells per 640-acre unit), regulatory approval allowed us to drill four wells during 2003 at locations that were effectively 40-acre spaced wells. Results from the four wells drilled at tighter spacing were encouraging. Of the four test wells drilled at 40-acre spacing, three wells indicated pressures near original reservoir pressures and one showed partial depletion. The data from the four 40-acre spaced wells indicates that a significant portion of the field will likely require 40-acre spaced wells to adequately develop the field, while other areas of the field will not. Continued downspacing should allow us to drill an additional 80 wells in the area in 2005 and beyond. We also intend to invest approximately $5.4 million in 2004 to drill 6-8 additional wells in other areas in East Texas.

Permian Basin. At December 31, 2003, our proved reserves in the Permian Basin were 55.6 Bcfe. Our production in the basin during 2003 was 4.2 Bcfe, or 11.5 MMcfe per day, and our production costs (including production taxes) averaged $1.15 per Mcfe. During 2003, our capital expenditures totaled $9.3 million, resulting in reserve additions of 9.8 Bcfe. Excluding reserve revisions, our three-year average finding and development cost in the basin was $1.16 per

Mcfe and three-year average reserve replacement ratio was 126% for the period ended December 31, 2003. During the past two years, we have deemphasized our exploration and development drilling activities in the Permian Basin and expect to continue to do so in 2004.

During the third quarter of 2003, we made a significant discovery on our River Ridge prospect located in Lea County, New Mexico. This discovery was made by deepening the Rio Blanco "4" Fed Com #1 well to the Devonian formation at 14,590 feet. This Devonian open-hole completion is currently producing at a rate of approximately 7.0 MMcf per day. We hold a 12.5% working interest in the discovery well. A second offset well in the prospect, the Rio Blanco "33" #1 well, reached a total depth of 15,000 feet in February 2004 and encountered gas-bearing intervals, as measured by drill-stem testing and open-hole logs, in the Devonian formation. The initial drill-stem test tested the top 100 feet of the Devonian formation and flowed 3.2 MMcf of gas per day at a pressure of 800 pounds per square inch. A second drill-stem test selectively tested 30 feet of deeper pay and yielded an additional 10.6 MMcf per day at a pressure of 2,800 pounds per square inch. We now believe the overall prospect has approximately 30 to 50 Bcfe of gross potential. We hold a 50% working interest in this well which is expected to be placed on production in March 2004.

Additionally in 2003, we increased the area's gross oil production to 144 barrels per day at year-end 2003, compared to 105 barrels per day at year-end 2002 as a result of several horizontal offset wells to our Birds of Prey discovery that was drilled in late 2002. We plan to invest approximately $7.8 million in our Permian Basin program to drill 12-16 exploration and exploitation wells in 2004.

Gulf Coast. Our Gulf Coast operations are located in the onshore areas of Texas and Louisiana. Our proved reserves in these areas totaled 39.5 Bcfe at December 31, 2003, of which approximately 12.3 Bcfe was located in Louisiana. At December 31, 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. Average net daily production in the Gulf Coast area was 12.3 MMcfe and production costs (including production taxes) averaged $1.23 per Mcfe during 2003. We invested $20.4 million in the area in 2003 and added 3.4 Bcfe of proved reserves. Excluding reserve revisions, our three-year average finding and development cost in the Gulf Coast region was $2.90 per Mcfe and three-year reserve replacement ratio was 139% for the period ending December 31, 2003.

In 2003, we participated in four exploration wells in South Louisiana, of which one was successful and one well was still drilling at year-end. During 2003, we drilled a discovery well on our Coleburn prospect located in Jefferson Parish. The SL 17780 #1 well reached a total depth of 13,000 feet in early October 2003 and encountered 33 feet of pay in the Tex W formation. The well is currently producing 3.8 MMcf per day and 70 barrels of condensate per day. We hold a 50% working interest in this well.

In late-2003, we commenced drilling our first well in our 135-square mile Duck Lake 3-D seismic project in St. Martin and St. Mary Parishes. In January 2004, the SL 17836 #1 well on our Canvasback prospect, targeting the Liebusella sands, reached a total depth of 17,821 feet. The well came in structurally high with the objective sands present, but the sands were not productive. We plan to test additional prospects in our Duck Lake 3-D project area as land and partners are put together.

Since our first discovery in December 1999, the efforts of our exploration program have resulted in 9 successful wells out of 21 wildcats drilled in South Louisiana. After three years of good drilling results from 1999 to 2001, we did not have a significant discovery in South Louisiana in 2002 or 2003. Our recent drilling activities in this area are not meeting our economic criteria, therefore we are reducing our investments in the Gulf Coast to $12.8 million in 2004. While we still plan to drill 4-8 exploration and development wells in the Gulf Coast area in 2004, we expect to decrease our activity in this area going forward.

New Ventures. In 2003, we began working on projects we are calling "New Ventures." During 2003, we acquired 345,310 net undeveloped leasehold acres in these project areas for approximately $11.0 million. This "New Venture" acreage more than doubled our total undeveloped acreage position at December 31, 2002. In addition, in early 2004, we acquired 95,000 net acres in a coal bed methane play located in the Crazy Mountain Basin in Montana. We plan to spud an initial test well on this acreage in the first quarter of 2004. If successful, we will follow this initial test well with a 4 to 8 well pilot program to further determine the economic viability of this project. In 2004, we plan to invest approximately $18.2 million in our "New Ventures" projects, of which approximately $4.0 million is dedicated to our coal bed methane play in Montana.

Acquisitions and Divestitures

In 2003, we purchased 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. One acquisition of note was the purchase of a 100% working interest in the Wright Unit and Roberson lease, located in the northeastern portion of our Overton Field, on which we drilled and completed 4 wells in 2003. Besides the existing production associated with these acquired properties, additional potential value was identified at the time of the acquisition related to future drilling opportunities, which resulted in a higher cost per Mcfe than those in recent history.

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.

In 2001, we purchased proved reserves of 4.5 Bcfe for $6.5 million, or $1.46 per Mcfe. The purchase included overriding royalty interests in the Arkoma Basin of 2.2 Bcfe, and additional working interests in the Overton Field of 1.9 Bcfe.

In April 2000, we purchased our initial interest in the Overton Field in Smith County, Texas, from Total Fina Elf for $6.1 million. Proved developed producing reserves associated with the purchase were 7.5 Bcfe, for a purchase price per Mcfe of $0.81. The purchase included 16 active gas wells in 13 spacing units, 8,800 contiguous acres in established units and 2,000 additional undeveloped acres outside those units.

In 1999, we purchased producing properties in the Permian Basin with estimated proved reserves of 9.4 Bcf of natural gas and 576 MBbls of oil, or 12.9 Bcfe. The properties were purchased from Petro-Quest Exploration, a privately held company headquartered in Midland, Texas, for $9.4 million.

As part of our current business strategy, 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 we believe have significant exploitation and exploration potential.

Capital Expenditures

We invested a total of $170.9 million in our E&P program and participated in drilling 139 wells during 2003. Of these drilled wells, 110 were successful, 16 were dry and 13 were still in progress at year-end. Our investments were balanced between our core areas of operations, with approximately $32.9 million invested in the Arkoma Basin, $97.3 million in East Texas, $9.3 million in the Permian Basin, $20.4 million in the Gulf Coast and $11.0 million in new venture areas. Of the $170.9 million invested, approximately $17.8 million was invested in exploratory drilling, $121.4 million in development drilling and workovers, $16.0 million for land and leasehold acquisition and seismic expenditures, $3.0 million for producing property acquisitions, and $12.7 million in capitalized interest and expenses and other technology-related expenditures.

In 2004, our planned E&P capital budget is $194.0 million, an increase of approximately 14% over our capital investment level in 2003. We continue to be focused on our strategy of adding value through the drillbit, as 80% of our 2004 E&P capital is allocated to drilling. Our investments in 2004 will primarily be focused on our lower-risk, high-return development drilling programs in East Texas and the Arkoma Basin. During 2004, we expect to invest approximately $110.9 million in East Texas and $44.3 million in the Arkoma Basin. The remainder of our E&P capital will be allocated to exploration and exploitation in the Permian Basin ($7.8 million), the onshore Gulf Coast ($12.8 million), and to new venture projects ($18.2 million). Of the $194.0 million capital budget, approximately $20.6 million will be invested in exploratory drilling, $133.9 million in development drilling and workovers, $21.0 million for land and leasehold acquisition and seismic expenditures, and $18.5 million in capitalized interest and expenses 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 2004.

Sales and Major Customers

Our daily natural gas equivalent production averaged 112.7 MMcfe in 2003, compared to 109.8 MMcfe in 2002 and 109.0 MMcfe in 2001. Our natural gas production was 38.0 Bcf in 2003, compared to 36.0 Bcf in 2002 and 35.5 Bcf in 2001. We also produced 531,000 barrels of oil in 2003, compared to 682,000 barrels of oil in 2002 and 719,000 barrels in 2001. We are targeting production in 2004 to be approximately 47.5 Bcfe to 50.0 Bcfe.

We realized an average wellhead price of $4.20 per Mcf for our natural gas production in 2003, compared to $3.00 per Mcf in 2002 and $3.85 per Mcf in 2001, including the effect of hedges. Our hedging activities lowered the average gas price $0.95 per Mcf in 2003, $0.11 per Mcf in 2002, and $0.31 per Mcf in 2001. Our average oil price realized was $26.72 per barrel in 2003, compared to $21.02 per barrel in 2002 and $23.55 per barrel in 2001, including the effect of hedges. Our hedging activities lowered the average oil price $2.94 per barrel in 2003, $2.92 per barrel in 2002 and $0.03 per barrel in 2001.

Our gas sales to unaffiliated purchasers were 32.1 Bcf in 2003, compared to 30.6 Bcf in 2002 and 30.4 Bcf in 2001. 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 86% of total E&P revenues in 2003, 85% in 2002 and 83% in 2001. In 2003, the largest unaffiliated purchaser accounted for 11% of total E&P revenues. This marketing arrangement ceased in late 2003.

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 12% of total E&P revenues in 2003, 15% in 2002 and 17% in 2001. SEECO’s sales to Arkansas Western were 5.9 Bcf in 2003, compared to 5.4 Bcf in 2002 and 5.1 Bcf in 2001. 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 41% of the utility’s requirements in 2003, 37% in 2002 and 33% in 2001. 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, 2003, we had hedges in place on 37.2 Bcf of 2004 and 2005 gas production and 426,000 barrels of 2004 oil production. Subsequent to December 31, 2003 and prior to February 23, 2004, we hedged 1.0 Bcf of 2005 gas production under costless collars with floor prices of $4.50 per Mcf and ceiling prices ranging from $8.30 to $8.40 per Mcf, and 3.0 Bcf of 2005 gas production swapped at an average price of $4.93 per Mcf. We currently have hedges in place on approximately 60–70% of our targeted 2004 gas production and approximately 70–80% of our 2004 targeted oil production. We refer you to Item 7A of this Form 10-K, “Quantitative and Qualitative Disclosures About Market Risks,” for further information regarding our hedge position at December 31, 2003.

Disregarding the impact of hedges, we expect the average price received for our gas production to be approximately $0.15 to $0.20 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, 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 in the acquisition of properties, the search for and development of reserves, the production and sale of oil and gas and the securing of the labor and equipment required to conduct 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

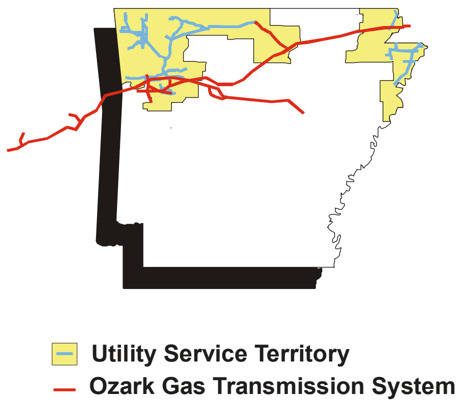
Sales of crude oil, condensate and gas liquids are not currently regulated and are made at negotiated prices. Effective January 1, 1995, the Federal Energy Regulatory Commission (the "FERC") implemented regulations establishing an indexing system for transportation rates for oil that allowed for an increase 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 the past, the federal government has regulated the prices at which gas could be sold. Sales by producers of natural gas can currently be made at uncontrolled market prices. The United States Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. 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. 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. The implementation of these orders has not had a material adverse effect on our results of operations. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. 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. Most major aspects of Order No. 637 are pending judicial review. 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 affected by any action taken in a materially different way than other natural gas producers and marketers with which we compete. 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 is 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 142,000 customers in northern Arkansas through our subsidiary, Arkansas Western. Our utility continues to capitalize on the healthy economy and sustained customer growth found in its Northwest Arkansas service territory. In April 2001, the U.S. Census Bureau listed Northwest Arkansas as the sixth fastest growing community in the United States. In June 2003, the Milken Institute named Northwest Arkansas as the "Best Performing City" in the United States, based upon job creation and local economic growth. As home to the largest public corporation in the world, Wal-Mart Stores, Inc., the region has experienced significant growth due to its presence in the area. Other major corporations such as Tyson Foods and J.B. Hunt Transportation have also significantly contributed to the area's growth. Approximately 86% of Arkansas Western's customers are located in this part of the state. 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.



Operating income for our natural gas distribution business was $6.8 million in 2003, compared to $7.6 million in 2002 and $10.3 million in 2001. EBITDA generated by our utility segment was $13.3 million in 2003, compared to $14.0 million in 2002 and $17.1 million in 2001. 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 operating income and EBITDA have decreased over the past few years primarily due to increased operating costs and expenses and reduced usage per customer brought about by high gas prices. 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. Arkansas Western had not had a rate increase since 1996.

On May 31, 2000, we completed the sale of our Missouri gas distribution assets for $32.0 million. The sale resulted in a pre-tax gain of approximately $3.2 million and proceeds from the sale were used to repay outstanding indebtedness.

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 2003, SEECO successfully bid on gas supply packages representing approximately 55% of the requirements for Arkansas Western for 2004.

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 6% of the utility's gas purchases are under take-or-pay contracts. Currently, 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. 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.

Markets and Customers

Arkansas Western provides natural gas to approximately 125,000 residential, 16,600 commercial, and 200 industrial customers, while also providing gas transportation services to approximately 70 end-use and off-system customers. Total gas throughput in 2003 was 25.0 Bcf, compared to 27.3 Bcf in 2002 and 27.1 Bcf in 2001. The lower volumes in 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 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. Off-system transportation volumes were 0.3 Bcf in 2003, 2.2 Bcf in 2002 and 3.1 Bcf in 2001.

Residential and Commercial. Approximately 87% of the utility's revenues in 2003 were from residential and commercial markets. Residential and commercial customers combined accounted for 60% of total gas throughput for the gas distribution segment in 2003, compared to 56% in 2002 and 54% in 2001. Gas volumes sold to residential customers were 9.0 Bcf in 2003, compared to 9.0 Bcf in 2002 and 8.4 Bcf in 2001. Gas sold to commercial customers totaled 6.1 Bcf in 2003, 6.2 Bcf in 2002 and 6.1 Bcf in 2001. The fluctuations in gas volumes sold 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 9.6 Bcf in 2003, 9.9 Bcf in 2002 and 9.5 Bcf in 2001. 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. A total of 67 customers are currently using the transportation service.

Competition

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. We experience increasing competition from alternative fuels such as electricity, fuel oil, and propane. Arkansas Western has historically maintained a price advantage over these fuels for most applications, enabling us to achieve excellent market penetration levels. 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 Arkansas Public Service Commission, or the APSC.

Regulation

Arkansas Western's utility rates and operations are regulated by the APSC. We operate 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 will conduct collaborative meetings to study the feasibility of a large-user access program for electric service choice. Although Arkansas Western already provides transportation service for its large users, this collaborative process 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 November 2002, Arkansas Western filed a request with the APSC for an adjustment in its rates totaling $11.0 million, or 9.1%, annually. The requested increase was the first Arkansas Western had made since 1996. 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 difference between the rate adjustment requested by Arkansas Western of $11.0 million annually and the final rate adjustment primarily resulted from a reduction in Arkansas Western's requested return on equity and a change in Arkansas Western's assumed capital structure. In the rate increase request that was filed with the APSC, Arkansas Western assumed an allowed return on equity of 12.9% and a capital structure of 48% debt and 52% equity. The APSC approved an allowed return on equity of 9.9% and an assumed capital structure of 52% debt and 48% equity. The 9.9% equity return was in line with the equity return approved in recent settlements that have been approved for the other two Arkansas local gas distribution companies. The rate increase was effective for all customer bills rendered on or after October 1, 2003. Arkansas Western's prior rate increase was approved in December 1996 for the utility's Northwest region and in December 1997 for its Northeast region. The APSC approved annual rate increases of $5.1 million and $1.2 million, respectively. The two operating regions have since been combined into one for the current rate increase.

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, 2003, Arkansas Western had under-recovered purchased gas costs of $1.1 million, compared to over-recovered purchase gas costs of $5.7 million in 2002 and $8.2 million in 2001.

Gas distribution revenues in future years will be impacted by customer growth and rate increases allowed by the 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 growth in its service territory in Northeast Arkansas. Based on current economic conditions in its service territories, we expect this trend in customer growth to continue.

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. Through utilization of our existing asset base, we are focused on creating and capturing value beyond the wellhead.

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 $2.6 million on revenues of $202.0 million in 2003, compared to $2.7 million on revenues of $131.1 million in 2002, and $2.7 million on revenues of $190.3 million in 2001. We marketed 42.7 Bcf of natural gas in

2003, compared to 45.5 Bcf in 2002 and 49.6 Bcf in 2001. 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 75% in 2003, 67% in 2002 and 66% in 2001.

Transportation

In January 1998, we entered into an agreement with Enogex Inc. a subsidiary of OGE Energy Corp., to expand the NOARK Pipeline and provide access to Oklahoma gas supplies through an integration of NOARK Pipeline with the Ozark Gas Transmission System. Ozark was a 437-mile interstate pipeline system that began in eastern Oklahoma and terminated in eastern Arkansas. Enogex acquired Ozark and contributed the pipeline system to the NOARK partnership. Enogex also acquired the NOARK partnership interests not held by us. On July 1, 1998, the FERC authorized the operation and integration of Ozark and NOARK Pipeline as a single, integrated pipeline. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK Pipeline that resulted in our interest in the partnership decreasing from approximately 48% to 25%, with Enogex owning the remaining 75% interest. There are also provisions in the agreement with Enogex which allow for revenue allocations to us above our 25% partnership interest if certain minimum throughput and revenue assumptions are not met.

The new integrated system, known as Ozark Pipeline, became operational November 1, 1998, and includes 723 miles of pipeline with a total throughput capacity of 330.0 MMcf per day. Deliveries are currently being 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 115.0 MMcf per day in 2003, compared to 168.1 MMcf per day in 2002 and 134.1 MMcf per day in 2001. The average daily throughput decreased in 2003 due primarily to a temporary curtailment by one of the interstate pipelines that connects with Ozark Pipeline.

At December 31, 2003, Arkansas Western had transportation contracts with Ozark Pipeline for 66.9 MMcf per day of firm capacity. These contracts expired in 2003, however they remain in effect and renew annually until terminated with 180 days' prior notice. NOARK and Arkansas Western are currently renegotiating the renewal of these contracts. The merged pipeline system now has greater access to major gas producing fields in Oklahoma. We expect that the pipeline's additional available throughput will create new marketing and transportation opportunities for us and reduce the losses NOARK has incurred in the past. The merged pipeline also provides our utility systems with additional access to gas supply. Our share of NOARK's results of operations was income of $1.1 million in 2003, and losses of $0.3 million in 2002 and $1.5 million in 2001. 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. We believe that we will be able to continue to reduce the losses we have experienced on the NOARK project and expect our investment in NOARK to be realized over the life of the system.

Other

Our wholly owned subsidiary, A. W. Realty Company, owns an interest in approximately 70 acres of real estate, most of which is undeveloped. 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. A.W. Realty continues to review with a joint venture partner various options for developing this property that would minimize our initial capital expenditures, but still enable us to retain an interest in any appreciation in value. During the third quarter of 2003, we sold 18.5 acres of commercial real estate located in Fayetteville, Arkansas for a pre-tax gain of $1.7 million, and we sold certain fixed assets for a pre-tax gain of $1.3 million, both of which 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 NOARK Pipeline previously competed with two interstate pipelines, one of which was the Ozark system, to obtain gas supplies for transportation to other markets. The integration with Ozark provides increased supplies to transport to both local markets and markets served by the three major interstate pipelines that Ozark Pipeline connects with in eastern Arkansas. We believe that the Ozark Pipeline will provide the additional gas supplies necessary to compete more effectively for the transportation of natural gas to end-users and markets served by the interstate pipelines.

Regulation

Prior to the integration with Ozark, the operations of NOARK Pipeline were regulated by the APSC. The integration of NOARK Pipeline with Ozark resulted in an interstate pipeline system subject to FERC regulations and FERC-approved tariffs. The FERC has set the maximum transportation rate of Ozark Pipeline 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, 2003, 2002 and 2001:

2003	E&P	Natural Gas Distribution	Marketing and Other	Total
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
2001				
Net income	$ 31,188	$ 4,028	$ 108	$ 35,324
Depreciation, depletion and amortization (1)	46,446	6,200	995	53,641
Net interest expense	18,238	4,413	1,048	23,699
Provision for income taxes	19,164	2,505	248	21,917
EBITDA	$115,036	$17,146	$ 2,399	$134,581

(1) Depreciation, depletion and amortization includes the amortization of restricted stock issued under our incentive compensation plan.

(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. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, there is 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 currently 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, most 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, 2003, we had 544 total employees, including 348 employed by our natural gas utility, of which 29 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 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 the future, we may require additional financing, in addition to cash generated from our operations, to fund our planned growth. We cannot be certain that 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.

The natural gas and oil reserves data we report are only estimates and may prove to be inaccurate.

There are numerous uncertainties, including many factors beyond our control inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures. Reserve data represent only estimates. In addition, the estimates of future net cash flows from our proved reserves and their present value are based upon various assumptions about future production levels, prices and costs that may prove to be incorrect over time. 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.

At December 31, 2003, approximately 18 percent of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assume that we can and will make these expenditures and conduct these operations successfully, which may not occur.

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.

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.

Our 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. 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, not all prospects result in viable projects resulting in the abandonment of 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.

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.

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.

Other companies 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. 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 will be outside our control, including the operator's expertise and financial resources, approval of other participants in drilling wells and selection 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 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 level of indebtedness may adversely affect operations and limit our growth.

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 subordinated 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.

At December 31, 2003, we had long-term indebtedness of $278.8 million, excluding our several guarantee of NOARK's debt obligation. Of this amount, $53.8 million was bank indebtedness under our then in effect revolving credit facility.

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. We currently have hedges on approximately 60–70% of our targeted 2004 natural gas production and approximately 70–80% of our targeted 2004 oil production. The Company's price risk management activities reduced revenues by $37.4 million in 2003, $6.1 million in 2002 and $10.3 million in 2001. 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 Disclosure about Market Risks."

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 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.

"Dekatherm" 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.

"Development drilling" 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.

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

"EBITDA" 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.

"Exploratory prospects or locations" 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.

"Finding and development costs" 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.

"Farm-in or farm-out" 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.

"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.

"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.

"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 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	390
Transmission	993
Distribution	3,900
	5,283

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, 2003:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Arkoma	136,380	91,683	231,097	164,679
East Texas	13,870	11,050	16,085	14,406
Permian Basin	30,107	16,182	89,135	25,382
New Ventures	671,482	345,310	-	-
Gulf Coast	43,450	21,540	35,116	11,809
	895,289	485,765	371,433	216,276

Producing wells as of December 31, 2003:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkoma	842	425.1	-	-	842	425.1
East Texas	107	101.1	2	2.0	109	103.1
Permian Basin	122	21.0	271	126.5	393	147.5
Gulf Coast	50	24.0	20	12.9	70	36.9
	1,121	571.2	293	141.4	1,414	712.6

Wells drilled during the year:

	Exploratory					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
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
2001	13.0	6.5	8.0	3.8	21.0	10.3

	Development					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
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
2001	67.0	29.5	11.0	2.9	78.0	32.4

Wells in progress as of December 31, 2003:

	Gross	Net
Exploratory	2.0	1.0
Development	11.0	8.7
Total	13.0	9.7

In January 2004, the SL 17836 #1 well on our Canvasback prospect in St. Martin Parish, Louisiana, targeting the Liebusella sands, reached a total depth of 17,821 feet. The well came in structurally high with the objective sands present, but the sands were not productive. We held a 50% working interest in this well. A second development well in our River Ridge prospect, the Rio Blanco "33" #1 well, reached a total depth of 15,000 feet in February 2004 and encountered gas-bearing intervals, as measured by drill-stem testing and open-hole logs, in the Devonian formation. The initial drill-stem test tested the top 100 feet of the Devonian formation and flowed 3.2 MMcf of gas per day at a pressure of 800 pounds per square inch. A second drill-stem test selectively tested 30 feet of deeper pay and yielded an additional 10.6 MMcf per day at a pressure of 2,800 pounds per square inch. We hold a 50% working interest in this well which is expected to be placed on production in March 2004.

During 2003, 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.

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, 2003, 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	59	7
Greg D. Kerley	Executive Vice President and Chief Financial Officer	48	14
Richard F. Lane	Executive Vice President, Southwestern Energy Production Company and SEECO, Inc.	46	5
Mark K. Boling	Executive Vice President, General Counsel and Secretary	46	2
Alan N. Stewart	Executive Vice President, Arkansas Western Gas Company	59	--

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 AND RELATED SHAREHOLDER MATTERS

Our common stock is traded on the New York Stock Exchange under the symbol "SWN." At December 31, 2003, we had 2,026 shareholders of record. The following prices represent closing market transactions on the New York Stock Exchange.

	Range of Market Prices			
Quarter Ended	**2003**		**2002**	
March 31	$13.23	$10.91	$12.80	$9.60
June 30	$16.35	$12.70	$15.25	$12.40
September 30	$18.55	$14.24	$15.22	$9.51
December 31	$25.48	$18.13	$12.44	$10.27

We have indefinitely suspended payment of quarterly 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 six-year period ended December 31, 2003. This information and the notes thereto is 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."

	2003	2002	2001	2000	1999
	(in thousands except share, per share, shareholder data and percentages)				
Financial Review					
Operating revenues					
Exploration and production	$ 176,245	$ 122,207	$ 153,937	$ 110,920	$ 75,039
Gas distribution	137,356	115,850	147,282	151,234	132,420
Gas marketing and other	205,449	131,514	190,773	208,196	137,942
Intersegment revenues	(191,649)	(108,069)	(147,065)	(106,467)	(65,005)
	327,401	261,502	344,927	363,883	280,396
Operating costs and expenses					
Gas purchases - utility	52,585	48,388	68,161	58,669	45,370
Gas purchases - marketing	39,428	37,927	68,010	133,221	92,851
Operating and general	70,479	64,600	64,108	59,790	57,957
Unusual items	—	—	—	111,288	—
Depreciation, depletion and amortization	55,948	53,992	52,899	45,869	41,603
Taxes, other than income taxes	11,619	10,090	9,080	8,515	6,557
	230,059	214,997	262,258	417,352	244,338
Operating income (loss)	97,342	46,505	82,669	(53,469)	36,058
Interest expense, net	(17,311)	(21,466)	(23,699)	(24,689)	(17,351)
Other income (expense)	797	(566)	(799)	1,997	(2,331)
Minority interest in partnership	(2,180)	(1,454)	(930)	—	—
Income (loss) before income taxes and accounting change	78,648	23,019	57,241	(76,161)	16,376
Income taxes					
Current	—	—	—	—	537
Deferred	28,896	8,708	21,917	(29,474)	5,912
	28,896	8,708	21,917	(29,474)	6,449
Income before accounting change	49,752	14,311	35,324	(46,687)	9,927
Cumulative effect of adoption of accounting principle	(855)	—	—	—	—
Net income (loss)	$ 48,897	$ 14,311	$ 35,324	$ (46,687)	$ 9,927
Net cash provided by operating activities	$ 109,099	$ 77,574	$ 144,583	$(53,203)(1)	$ 58,131
Return on equity	14.3%	8.1%	19.3%	n/a	5.2%
Common Stock Statistics					
Earnings (loss) per share:					
Basic	$ 1.46	$ .57	$ 1.40	$ (1.86)	$ .40
Diluted	$ 1.43	$ .55	$ 1.38	$ (1.86)	$ .40
Cash dividends declared and paid per share	$ —	$ —	$ —	$ .12	$ .24
Book value per average diluted share	$ 9.98	$ 6.81	$ 7.15	$ 5.64	$ 7.63
Market price at year-end	$ 23.90	$ 11.45	$ 10.40	$ 10.38	$ 6.56
Number of shareholders of record at year-end	2,026	2,079	2,124	2,192	2,268
Average diluted shares outstanding	34,237,934	26,052,238	25,601,110	25,043,586	24,947,021

(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.

	2003	2002	2001	2000	1999
Capitalization (in thousands)					
Total debt, including current portion	$ 278,800	$ 342,400	$ 350,000	$ 396,000	$ 302,200
Common shareholders' equity(1)	341,561	177,488	183,086	141,291	190,356
Total capitalization	$ 620,361	$ 519,888	$ 533,086	$ 537,291	$ 492,556
Total assets	$ 890,710	$ 740,162	$ 743,123	$ 705,378	$ 671,446
Capitalization ratios:					
Debt	44.9%	65.9%	65.7%	73.7%	61.4%
Equity	55.1%	34.1%	34.3%	26.3%	38.6%
Capital Expenditures (in millions)					
Exploration and production(2)	$ 170.9	$ 85.2	$ 99.0	$ 69.2	$ 59.0
Gas distribution	8.2	6.1	5.3	6.0	7.1
Other	1.1	.8	1.8	.5	.9
	$ 180.2	$ 92.1	$ 106.1	$ 75.7	$ 67.0
Exploration and Production					
Natural gas:					
Production, Bcf	38.0	36.0	35.5	31.6	29.4
Average price per Mcf, including hedges	$ 4.20	$ 3.00	$ 3.85	$ 2.88	$ 2.21
Average price per Mcf, excluding hedges	$ 5.15	$ 3.11	$ 4.16	$ 3.92	$ 2.27
Oil:					
Production, MBbls	531	682	719	676	578
Average price per barrel, including hedges	$ 26.72	$ 21.02	$ 23.55	$ 22.99	$ 17.11
Average price per barrel, excluding hedges	$ 29.66	$ 23.94	$ 23.58	$ 29.38	$ 17.04
Total gas and oil production, Bcfe	41.2	40.1	39.8	35.7	32.9
Lease operating expenses per Mcfe	$ .39	$ .45	$ .45	$ .40	$ .35
Taxes other than income taxes per Mcfe	$ .22	$ .19	$ .17	$ .16	$ .09
Proved reserves at year-end:					
Natural gas, Bcf	457.0	374.6	355.8	331.8	307.5
Oil, MBbls	7,675	6,784	7,704	8,130	7,859
Total reserves, Bcfe	503.1	415.3	402.0	380.6	354.7
Gas Distribution(3)					
Sales and transportation volumes, Bcf:					
Residential	9.0	9.0	8.4	10.9	10.8
Commercial	6.1	6.2	6.1	7.6	7.6
Industrial	1.2	1.5	2.5	3.5	3.5
End-use transportation	8.4	8.4	7.0	8.3	9.6
	24.7	25.1	24.0	30.3	31.5
Off-system transportation	0.3	2.2	3.1	3.1	4.8
	25.0	27.3	27.1	33.4	36.3
Customers at year-end:					
Residential	124,776	122,906	119,856	119,024	158,606
Commercial	16,623	16,448	16,177	16,282	21,929
Industrial	174	189	209	228	290
	141,573	139,543	136,242	135,534	180,825
Degree days	3,969	3,950	3,654	3,994	3,179
Percent of normal	99%	98%	91%	100%	79%

(1) Shareholders' equity includes an accumulated other comprehensive loss of $12.5 million in 2003 ($12.0 million related to our cash flow hedges and $0.5 million related to our pension plan), $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) Exploration and Production capital expenditures for 2003 include $12.0 million of accrued expenditures.

(3) Gas distribution statistics include the operations of the Missouri properties through the sale date of 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 and transportation services in our core areas of operation. We operate our business in three segments: Exploration and Production, Natural Gas Distribution and Natural Gas Marketing.

Our financial 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' need 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 $48.9 million in 2003, or $1.43 per share on a fully diluted basis, up from $14.3 million, or $0.55 per share in 2002. In 2001, we reported net income of $35.3 million, or $1.38 per share on a fully diluted basis. The increase in net income in 2003 was primarily a result of higher realized natural gas and oil prices and increased production volumes in our Exploration and Production, or E&P segment. The decrease in net income in 2002 was primarily the result of lower realized natural gas and oil prices on the operating income of our E&P segment. Operating income for our E&P segment was $84.7 million in 2003, up from $36.0 million in 2002 and $69.3 million in 2001. Operating income for our gas distribution segment was $6.8 million in 2003, compared to $7.6 million in 2002 and $10.3 million in 2001. The decreases in operating income for our gas distribution segment resulted from increased operating costs and expenses primarily related to higher pension, insurance and incentive compensation costs. Our cash flow from operating activities was $109.1 million in 2003, compared to $77.6 million in 2002 and $144.6 million in 2001. In 2001, our cash flow from operating activities included significant collections of accounts receivable and deferred gas costs that were generated in late 2000 by extremely high gas costs at that time.

In 2003, our gas and oil production continued to increase, reaching 41.2 Bcfe, up 3% from 40.1 Bcfe in 2002 and 39.8 Bcfe in 2001. The increase in 2003 production resulted from an increase in production from our Overton Field in East Texas due to accelerated development of the field, which was partially offset by the loss of production from the sale of our Mid-Continent properties in late 2002 and declining production from our South Louisiana properties. Our Mid-Continent properties historically provided approximately 2.5 Bcfe of production annually. Production growth in 2003, without consideration of the sale of Mid-Continent properties, would have been approximately 8%.

In our E&P segment, we achieved a reserve replacement ratio of 351% in 2003 at a finding and development cost of $1.18 per Mcfe, excluding reserve revisions. Our year-end reserves grew 21% to 503.1 Bcfe, up from 415.3 Bcfe at the end of 2002. Our results were primarily fueled by our continued drilling success in our Overton Field in East Texas as well as our continued successful development drilling program in the Arkoma Basin.

Our capital investments totaled $180.2 million in 2003, up from $92.1 million in 2002 and $106.1 million in 2001. We invested $170.9 million in our E&P segment in 2003, compared to $85.2 million in 2002 and $99.0 million in 2001. Funds for our 2003 capital investments were provided by cash flow from operations and the $103.1 million of net proceeds from the sale of 9,487,500 shares of our common stock in the first quarter of 2003.

Our equity offering in the first quarter of 2003, combined with our earnings during the year, improved our financial position and reduced our total debt-to-capitalization ratio to 45% at December 31, 2003 from 66% at December 31, 2002.

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 adding 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.

Capital investments planned for 2004 total $203.5 million, including $194.0 million for our E&P segment, which is an increase of 14% over our E&P capital investments in 2003. We continue to be focused on our strategy of adding value through the drillbit, as 80% of our 2004 E&P capital is allocated to drilling. Our E&P investments in 2004 will primarily be focused on our lower-risk, higher rate of return development drilling programs in East Texas and the Arkoma Basin. We expect our capital program in 2004 to contribute to a targeted production and reserve growth of 15–20%. In 2004 we are targeting production to be approximately 47.5 Bcfe to 50.0 Bcfe, compared to 41.2 Bcfe in 2003. Our capital investments in 2004 will be funded by cash flow from operations and borrowings under our revolving credit facilities.

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 2003.

RESULTS OF OPERATIONS

Exploration and Production

	Year Ended December 31,		
	2003	2002	2001
Revenues (in thousands)	$176,245	$122,207	$153,937
Operating income (in thousands)	$ 84,737	$ 36,048	$ 69,340
Gas production (Bcf)	38.0	36.0	35.5
Oil production (MBbls)	531	682	719
Total production (Bcfe)	41.2	40.1	39.8
Average gas price per Mcf, including hedges	$ 4.20	$ 3.00	$ 3.85
Average gas price per Mcf, excluding hedges	$ 5.15	$ 3.11	$ 4.16
Average oil price per Bbl, including hedges	$ 26.72	$ 21.02	$ 23.55
Average oil price per Bbl, excluding hedges	$ 29.66	$ 23.94	$ 23.58
Average unit costs per Mcfe			
Lease operating expenses	$ 0.39	$ 0.45	$ 0.45
Taxes other than income taxes	$ 0.22	$ 0.19	$ 0.17
General & administrative expenses	$ 0.41	$ 0.32	$ 0.34
Full cost pool amortization	$ 1.17	$ 1.16	$ 1.14

Revenues, Operating Income and Production

Revenues. Our exploration and production revenues increased 44% in 2003 to $176.2 million compared to $122.2 million in 2002. The increase was primarily due to higher prices received for our natural gas and oil production and to slightly increased gas production volumes. Revenues decreased 21% in 2002 from $153.9 million in 2001. The decrease was primarily due to lower prices received for natural gas.

Operating Income. Operating income from our exploration and production segment was $84.7 million in 2003, up from $36.0 million in 2002 and $69.3 million in 2001. The increase in 2003 was due to a 40% increase in the average price received for our natural gas production and a 3% increase in our equivalent production volumes, partially offset by increased operating costs and expenditures. The decrease in 2002 was primarily due to a decrease in revenues caused by the lower realized natural gas prices.

Production. Gas and oil production totaled 41.2 Bcfe in 2003, 40.1 Bcfe in 2002 and 39.8 Bcfe in 2001. The increase in 2003 production resulted from an increase in production from our Overton Field in East Texas due to the accelerated development of the field, partially offset by declines experienced in our South Louisiana properties that began in the last half of 2002, combined with the loss of production resulting from the November 2002 sale of our non-strategic Mid-Continent properties. Production from our Mid-Continent properties historically averaged approximately 2.5 Bcfe annually. Overall production in 2002 was up slightly over 2001 as increased production from our Overton Field properties in East Texas and from our Gulf Coast properties more than offset production declines in our Arkoma Basin and Permian Basin properties.

Gas sales to unaffiliated purchasers were 32.1 Bcf in 2003, up from 30.6 Bcf in 2002 and 30.4 Bcf in 2001. 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 5.9 Bcf in 2003, 5.4 Bcf in 2002 and 5.1 Bcf in 2001. 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 2003, as measured in degree days, was 1% warmer than normal and approximately even with the prior year. Weather in 2002 was 2% warmer than normal and 8% colder than the prior year. Weather in 2001 was 9% warmer than both normal and the prior year. Our gas production provided approximately 41% of the utility's requirements in 2003, 37% in 2002 and 33% in 2001.

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, we will continue to bid to obtain these gas supply contracts, although there is 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 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. 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

The average price realized for our gas production, including the effects of hedges, was $4.20 per Mcf in 2003, $3.00 per Mcf in 2002 and $3.85 per Mcf in 2001. 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 $0.95 per Mcf in 2003, $0.11 per Mcf in 2002 and $0.31 per Mcf in 2001. Additionally, we have historically received demand charges related to sales made to our utility segment, which has increased our average gas price realized.

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 financial statements for additional discussion). Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2003, we had hedges in place on 37.2 Bcf of 2004 and 2005 gas production. Subsequent to December 31, 2003 and prior to February 23, 2004, we hedged an additional 4.0 Bcf of future gas production. At December 31, 2003 we had hedges in place on 426,000 barrels of 2004 oil production. As of February 23, 2004, we have hedged approximately 60-70% of our 2004 anticipated gas production level and 70-80% of our 2004 anticipated oil production level.

Disregarding the impact of hedges, we would normally expect the average price received for our gas production to be approximately $0.15 to $0.20 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. Future changes in revenues from sales of our gas production will be dependent upon changes in the market price for gas, access to new markets, maintenance of existing markets, and additions of new gas reserves.

We realized an average price of $26.72 per barrel, including the effects of hedges, for our oil production for the year ended December 31, 2003, up from $21.02 per barrel for 2002 and $23.55 per barrel for 2001. Our hedging activities lowered the average oil price $2.94 per barrel in 2003, $2.92 per barrel in 2002 and $0.03 per barrel in 2001. 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.

Operating Costs and Expenses

Lease operating expenses per Mcfe for this business segment were $0.39 in 2003, down from $0.45 in both 2002 and 2001. Lease operating expenses per unit decreased in 2003 due to changes in the geographic mix of our production and higher workover expenses in 2002. Taxes other than income taxes per Mcfe were $0.22 in 2003, compared to $0.19 in 2002 and $0.17 in 2001. The increase in 2003 taxes other than income taxes per Mcfe was due to increased severance and ad valorem taxes that resulted from generally higher commodity prices and from the changing mix of our production among taxing jurisdictions. General and administrative expenses per Mcfe were $0.41 in 2003, compared to $0.32 in 2002 and $0.34 in 2001. The increase in general and administrative costs per Mcfe in 2003 was due primarily to increased pension, insurance and incentive compensation costs. We expect our cost per Mcfe for operating and general and administrative expense to decline in 2004 primarily due to our anticipated increase in production. Future changes in our general and administrative expenses 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.

Our full cost pool amortization rate averaged $1.17 per Mcfe for 2003, compared to $1.16 in 2002 and $1.14 in 2001. 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. Unevaluated costs excluded from amortization were $39.0 million at the end of 2003, compared to $25.5 million at the end of 2002 and $26.2 million at the end of 2001. The increase in unevaluated costs at December 31, 2003 primarily resulted from unproved costs for wells in progress at year-end and an increase in our undeveloped leasehold acreage related to our new venture areas.

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, 2003, 2002 and 2001, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2003, our standardized measure was calculated based upon quoted market prices of $5.97 per Mcf for gas and $32.52 per barrel for oil, adjusted for market differentials. A decline in natural gas and oil prices from year-end 2003 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.

In 2001, our subsidiary, SEPCO, formed a limited partnership with an investor to drill and complete 14 development wells in SEPCO's Overton Field located in Smith County, Texas. The Overton properties were acquired by SEPCO in April 2000 and have multiple development locations through the downspacing of the existing producing units. Because SEPCO is the sole general partner and owns a majority interest in the partnership, operating and financial results for the partnership are consolidated with our other operations and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. During 2003, 2002 and 2001, the minority interest owner in the partnership contributed $0.1 million, $0.5 million and $13.5 million, respectively, in capital to the limited partnership. The investor's share of 2003, 2002 and 2001 revenues, less operating costs and expenses, was $2.2 million, $1.5 million and $0.9 million, respectively.

Inflation impacts us 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 2003 with an increase in the industry activity level caused by higher commodity prices. Southwestern has mitigated rising costs in certain situations by obtaining vendor commitments to multiple projects and by offering incentives to vendors for increased efficiencies resulting in cost reductions.

Natural Gas Distribution

	Year Ended December 31,		
	2003	2002	2001
	($ in thousands except for per Mcf amounts)		
Revenues	$137,356	$115,850	$147,282
Gas purchases	$ 84,926	$ 66,486	$ 96,058
Operating costs and expenses	$ 45,664	$ 41,801	$ 40,878
Operating income	$ 6,766	$ 7,563	$ 10,346
Deliveries (Bcf)			
Sales and end-use transportation	24.7	25.1	24.0
Off-system transportation	0.3	2.2	3.1
Customers at year-end	141,573	139,543	136,242
Average sales rate per Mcf	$ 7.93	$ 6.49	$ 8.26
Heating weather - degree days	3,969	3,950	3,654
Percent of normal	99%	98%	91%

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 net income.

Gas distribution revenues increased 19% in 2003 and decreased 21% in 2002. The increase in 2003 gas distribution revenues was primarily due to a higher average sales rate caused by higher gas prices. The decrease in 2002 was primarily due to a lower average sales rate caused by lower gas prices. Weather during 2003 in the utility's service territory was 1% warmer than normal and slightly above the prior year. Weather during 2002 was 2% warmer than normal and 8% colder than the prior year, and was 9% warmer than both normal and the prior year in 2001.

Operating income for our utility systems decreased 11% in 2003 and decreased 27% in 2002. The decrease in 2003 and 2002 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 will increase 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. Operating income in 2003 included a gain of $1.0 million related to the recovery of these costs. Gas distribution revenues in future years will be impacted by the utility's gas purchase costs, customer growth and rate increases allowed by the 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.

Deliveries and Rates

In 2003, Arkansas Western sold 16.3 Bcf to its customers at an average rate of $7.93 per Mcf, compared to 16.7 Bcf at $6.49 per Mcf in 2002 and 17.0 Bcf at $8.26 per Mcf in 2001. Additionally, Arkansas Western transported 8.4 Bcf in 2003 and 2002, and 7.0 Bcf in 2001 for its end-use customers. The decrease in volumes sold in 2003 primarily resulted from variations in weather and customer conservation brought about by high gas prices in recent years. The decrease in volumes sold in 2002 resulted from customer conservation and from several industrial customers moving from system supply to transportation. 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 fluctuations in the average sales rates reflect 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 9.6 Bcf in 2003, 9.9 Bcf in 2002 and 9.5 Bcf in 2001. The decrease in deliveries in 2003 was due to customer conservation brought about by high gas prices partially offset by continued industrial growth in the region. Arkansas Western also transported 0.3 Bcf of gas through its gathering system in 2003 compared to 2.2 Bcf in 2002 and 3.1 Bcf in 2001 for off-system deliveries, all to the Ozark Gas Transmission System. 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. The average off-system transportation rate was approximately $0.13 per Mcf, exclusive of fuel, in 2003, 2002 and 2001.

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 increased in 2003 as compared to 2002 due to general inflationary effects, increased general and administrative expenses and increased transmission expense. The increase in general and administrative expenses resulted from increases in pension, insurance and incentive compensation costs. The increase in transmission expense resulted from higher fuel costs. Operating costs and expenses increased in 2002 as compared to 2001 due to general inflationary effects and increased pension and insurance costs. Operating costs in 2001 also included increased bad debt expense caused by high natural gas prices in the 2000-2001 winter heating season. Future changes in our general and administrative expenses 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 2003-2004 gas purchase year, SEECO successfully bid on gas supply packages representing approximately 55% of the requirements for Arkansas Western for 2004. The contracts awarded to SEECO expire through 2005. 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. We refer you to "Quantitative and Qualitative Disclosure About Market Risks" and Note 8 to the 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 are not 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.

In Arkansas, the state legislature enacted Act 1556 for the deregulation of the retail sale of electricity by 2002. In December 2001, the APSC submitted its annual report to the Arkansas legislature on the development of electric deregulation and recommended that the legislature consider suspending deregulation to the year 2010 or 2012, or repeal Act 1556 (as modified by Act 324). In 2003, Act 1556 was repealed. During 2004, the APSC will conduct collaborative meetings to study the feasibility of a large user access program for electric service choice. Although Arkansas Western already provides transportation service for its large users, this collaborative process 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.

Arkansas Western has historically maintained a price advantage over electricity for most applications. This has enabled the utility to achieve excellent market penetration levels. However, during 2001 the high gas prices experienced in the 2000-2001 heating season temporarily eroded the price advantage. Arkansas Western has made progress in regaining price advantage in its markets as gas prices have declined from the levels experienced in the winter of 2000-2001.

Arkansas Western filed an application with the APSC on November 8, 2002, for a rate increase of $11.0 million annually. In the third quarter of 2003 we 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. Arkansas Western's last rate increase was approved in December 1996 for its Northwest region and in December 1997 for its Northeast region. The APSC approved increases of $5.1 million and $1.2 million, respectively. The two operating regions have since been combined into one.

The difference between the $11.0 million rate adjustment requested by Arkansas Western and the rate adjustment contained in the approved order primarily results from a reduction in Arkansas Western's requested return on equity and a change in Arkansas Western's assumed capital structure. In the rate increase request that was filed with the APSC, 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. The 9.9% equity return is in line with the equity return approved in recent settlements that have been approved for the other two Arkansas local gas distribution companies. 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.

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. If the plan includes a hedging strategy and it is determined to be consistent with the objectives of the policy principles, utilities will be allowed to flow any hedging gain or loss to customers through the purchased gas adjustment clause.

During 2001, Arkansas Western submitted its annual gas supply plan for the 2001-2002 heating season and a revision to its purchased gas adjustment clause for the recovery of hedging gains and losses to the staff of the APSC. In May 2002 and April 2003, Arkansas Western submitted its annual gas supply plan for the 2002-2003 and 2003-2004 heating seasons.

Arkansas Western also purchases gas from unaffiliated producers under take-or-pay contracts. We believe that we do not have a 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 and Transportation

Marketing

	Year Ended December 31,		
	2003	2002	2001
Revenues (in millions)	$ 202.0	$ 131.1	$ 190.3
Operating income (in millions)	$ 2.6	$ 2.7	$ 2.7
Gas volumes marketed (Bcf)	42.7	45.5	49.6

Our operating income from natural gas marketing was $2.6 million on revenues of $202.0 million in 2003, compared to $2.7 million on revenues of $131.3 million in 2002 and $2.7 million on revenues of $190.3 million in 2001. The increase in revenues in 2003 resulted from higher prices received for gas sold and was offset by a corresponding increase in gas purchase expense. We marketed 42.7 Bcf in 2003, compared to 45.5 Bcf in 2002 and 49.6 Bcf in 2001. The decline in total volumes marketed in 2003 and 2002 resulted primarily from the decline in volumes marketed to third parties. This reduction reflects our continued focus on marketing our own production and limiting the marketing of third-party volumes in an effort to reduce our credit risk. Of the total volumes marketed, production from our exploration and production subsidiaries accounted for 75% in 2003, 67% in 2002 and 66% in 2001. 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 Disclosure About Market Risks" and Note 8 to the financial statements for additional discussion.

Transportation

Our marketing group also manages our 25% interest in NOARK. At December 31, 2003, Arkansas Western had transportation contracts with Ozark Pipeline for 66.9 MMcf per day of firm capacity. These contracts are renewable annually until terminated with 180 days' notice. NOARK and Arkansas Western are currently renegotiating these contracts. We recorded pre-tax income from operations related to our NOARK investment of $1.1 million in 2003, compared to pre-tax losses of $0.3 million in 2002 and $1.5 million in 2001. These amounts are recorded in other income (expense) in our income statement. The pre-tax gain in 2003 included a gain of $1.3 million recognized on the sale of a 28-mile portion of NOARK's pipeline located in Oklahoma that had limited strategic value to the overall system. The trend in improved operating results has been primarily caused by NOARK's ability to collect higher transportation rates on interruptible volumes. We believe that we will be able to continue to improve NOARK's operating results and expect our investment in NOARK to be realized over the life of the system. We refer you to Note 7 to the financial statements for additional discussion.

We have severally guaranteed the debt service on a portion of NOARK's outstanding debt. NOARK's outstanding debt was $69.0 million at December 31, 2003, and our share of the guarantee was $41.4 million. This debt financed a portion of the original cost to construct the NOARK Pipeline. We were not required to advance any funds to NOARK in 2003 and 2002, but we advanced $1.4 million in 2001 primarily for debt service. 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 financial statements for further discussion of our guarantee of NOARK debt.

Interest Expense

Interest costs, net of capitalization, were down 19% in 2003 and down 9% in 2002, both as compared to prior years. The decreases in interest costs were due to both comparatively lower average borrowings and lower average interest rates. In 2003, our average borrowings again 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. We are reborrowing the repaid amounts under the credit facility, as necessary, to fund the acceleration of the development of our Overton Field in East Texas and for general corporate purposes. Interest capitalized increased 21% in 2003 and decreased 7% in 2002. Changes in capitalized interest are primarily due to the level of costs excluded from amortization in our E&P segment.

Income Taxes

Our provision for deferred income taxes was an effective rate of 36.7% in 2003, 37.8% in 2002 and 38.3% in 2001. The changes in the provision for deferred income taxes recorded each year result primarily from the level of taxable income, the collection of under-recovered purchased gas costs, abandoned property costs, and the deduction of intangible drilling costs in the year incurred for tax purposes, netted against the turnaround of intangible drilling costs deducted for tax purposes in prior years. Intangible drilling costs are capitalized and amortized over future years for financial reporting purposes under the full cost method of accounting.

Pension Expense

We recorded pension expense of $3.3 million in 2003, $0.9 million in 2002 and a credit to expense of $0.1 million in 2001. 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 2003, we funded our pension plan with contributions of $3.0 million. At December 31, 2003, our pension plans were underfunded and a liability of $0.9 million was recorded on the balance sheet. As a result of the underfunded status and actuarial data to be completed in early 2004, we expect to record pension expense of $2.5 million to $3.0 million in 2004. For further discussion of our pension plans, we refer you to Note 4 to the financial statements and "Critical Accounting Policies" below.

Other Revenues

Revenues and operating income in 2003 included pre-tax gains of $3.0 million related to the sale of real estate and certain property and equipment, and $3.1 million of pre-tax gain related to the sale of gas-in-storage inventory.

Adoption of Accounting Principle

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, 2003, we had $0.2 million of current liabilities and $7.4 million of long-term liabilities associated with our asset retirement obligations. Subsequent to adoption, we do not expect this standard to have a material impact on our future financial position or our results of operations.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds and our unsecured revolving credit facilities (discussed below under "Financing Requirements") as our primary sources of liquidity. We may borrow up to $315 million under our new revolving credit facilities from time to time. As of February 23, 2004, we had $49.1 million of indebtedness outstanding under our revolving credit facilities. During 2004 we expect to draw on a portion of the funds available under our credit facilities to fund our planned capital expenditures (discussed below under “Capital Expenditures”) for 2004 which are expected to exceed the net cash generated by our operations. In December 2002, we filed a shelf registration statement with the SEC pursuant to which we may from time to time, subject to market conditions, publicly offer equity, debt or other securities.

Net cash provided by operating activities was $109.1 million in 2003, compared to $77.6 million in 2002 and $144.6 million in 2001. 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 2003 due primarily to increased net income and the related increase in deferred income taxes. In 2001, $55.4 million of the $144.6 million of cash provided by operating activities resulted from changes in our operating assets caused by the collection of accounts receivable and under-recovered purchased gas costs that resulted from the extremely high gas prices that were in effect at the end of 2000. Net cash from operating activities provided 65% of our cash requirements for capital expenditures in 2003, 84% in 2002 and over 100% in 2001.

Our cash flow from operating activities is highly dependent upon market prices that we receive for our gas and oil production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in “Quantitative and Qualitative Disclosure About Market Risks” and Note 8 to the financial statements. Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon cash flow available.

Capital Expenditures

Capital expenditures totaled $180.2 million in 2003, $92.1 million in 2002 and $106.1 million in 2001. In 2003, capital expenditures for our E&P segment included $12.0 million of accrued expenditures. Additionally, our E&P segment expenditures included acquisitions of interests in natural gas and oil producing properties totaling $3.0 million in 2003, $3.5 million in 2002 and $7.3 million in 2001. Our reported capital investments for 2003, 2002 and 2001 include the gross expenditures in the Overton Field partnership discussed previously. The owner of the minority interest in the Overton partnership funded $0.5 million and $13.5 million of our E&P expenditures during 2002 and 2001, respectively.

	2003	2002	2001
		(in thousands)	
Exploration and production	$ 170,886	$ 85,201	$ 98,964
Gas distribution	8,178	6,115	5,347
Other	1,139	746	1,749
	$ 180,203	$ 92,062	$ 106,060

Our capital investments planned for 2004 total $203.5 million, consisting of $194.0 million for exploration and production, $7.9 million for gas distribution system improvements and $1.6 million for general purposes. We expect that this level of capital investments in 2004 will allow us to accelerate the development of our Overton Field properties in East Texas, 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 2004 capital investment program is expected to be funded through cash flow from operations and our revolving credit facilities. We may adjust the level of 2004 capital investments dependent upon our level of cash flow generated from operations.

Off-Balance Sheet Arrangements

As discussed above in "Results of Operations," we hold a 25% general partnership interest in NOARK, which owns the Ozark Pipeline 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. This debt financed a portion of the original cost to construct the NOARK Pipeline. Our share of the guarantee is 60% and we are allocated 60% of the interest expense. At December 31, 2003 and 2002, the outstanding principal amount of these notes was $69.0 million and $71.0 million, respectively. Our share of the guarantee was $41.4 million and $42.6 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 were not required to advance any funds to NOARK in 2003 and 2002, and advanced $1.4 million in 2001. 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 pre-tax income of $1.1 million in 2003, and pre-tax losses of $0.3 million in 2002 and $1.5 million in 2001. 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 NOARK's pipeline system in Oklahoma. The improvement in operating results in 2003 and 2002 resulted primarily from the ability to collect higher transportation rates on interruptible volumes. 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, 2003 and 2002 are as follows:

	2003	2002
	(in thousands)	
Current assets	$ 20,642	$ 15,730
Noncurrent assets	161,994	169,970
	$ 182,636	$ 185,700
Current liabilities	$ 7,537	$ 7,631
Long-term debt	67,000	69,000
Partners' capital	108,099	109,069
	$ 182,636	$ 185,700

NOARK's results of operations for 2003, 2002 and 2001 are summarized below:

	2003	2002	2001
		(in thousands)	
Operating revenues	$ 72,038	$ 75,959	$ 81,662
Pre-tax income (loss)	$ 9,030	$ 3,011	$ (1,047)

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, 2003 are 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	$ 278,800	$ —	$ 125,000	$ 53,800	$ 100,000
Operating leases(1)	6,126	1,224	2,183	911	1,808
Unconditional purchase obligations(2)	—	—	—	—	—
Demand charges(3)	24,424	11,396	6,192	2,898	3,938
Other obligations(4)	5,567	5,467	50	50	—
	$ 314,917	$ 18,087	$ 133,425	$ 57,659	$ 105,746

(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, 2003 totaled 2.5 Bcf, comprised of 1.2 Bcf in less than one year, 0.8 Bcf in one to three years, 0.3 Bcf in three to five years and 0.2 Bcf in more than 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 $18.0 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 $6.4 million of demand transportation charges.

(4) Our significant other contractual obligations include approximately $2.8 million for funding of benefit plans, approximately $0.6 million of land leases, approximately $1.0 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" below 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, combined with other factors, resulted in an increase in pension expense and our required funding of the plans for 2003. At December 31, 2003 we recorded an accrued pension benefit liability of $0.9 million. As a result of the underfunded status and actuarial data to be completed in early 2004, we expect to record pension expense of $2.5 million to $3.0 million in 2004. 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, 2003 the principal outstanding for these notes was $69.0 million. The notes require semi-annual principal payments of $1.0 million. See Note 11 to the financial statements for additional information.

Financing Requirements

Our total debt outstanding was $278.8 million at December 31, 2003 and $342.4 million at December 31, 2002. In January 2004, we entered into a new $300 million three-year unsecured revolving credit facility with a group of banks which replaced our previous $125 million credit facility that was due to expire in July 2004. We also have access to an additional $15 million of borrowing capacity under a separate three-year unsecured credit facility entered into at the same time. At December 31, 2003, we had $53.8 million of outstanding debt under our prior revolving credit facility. The interest rate on each of the new facilities is calculated based upon our public debt rating and is currently 125 basis points over LIBOR. Our publicly traded notes are rated BBB by Standard and Poor's and Ba2 by Moody's. Any downgrades in our public debt ratings could increase the cost of funds under our revolving credit facilities.

Our revolving credit facilities contain 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 debt agreements at December 31, 2003. Although we do not anticipate debt covenant violations, our ability to comply with our debt agreements 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.

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 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. We are reborrowing the repaid amounts as necessary to fund the acceleration of the development of our Overton Field in East Texas and for general corporate purposes.

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 $41.4 million at December 31, 2003. We did not advance any funds to NOARK in 2003 and 2002 and advanced $1.4 million in 2001. If NOARK is unable to generate sufficient cash in the future to service its debt and we are 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 2003, our capital structure consisted of 45% debt (excluding our several guarantee of NOARK's obligations) and 55% equity, with a ratio of EBITDA to interest expense of 8.80. 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, 2003 balance sheet includes an accumulated other comprehensive loss of $12.0 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, 2003, and does not necessarily reflect the value that we will receive when the hedges are ultimately 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, would be 48% debt and 52% equity at December 31, 2003 without consideration of the accumulated other comprehensive loss related to FAS 133. As part of our strategy to insure a certain level of cash flow to fund our operations, we have hedged approximately 60-70% of our expected 2004 gas production and 70-80% of our expected 2004 oil production. The amount of long-term debt we incur is dependent upon commodity prices and our capital expenditure plans. If commodity prices remain at or near current levels throughout 2004 and our capital expenditure plans do not change from current expectations, we will increase our long-term debt in 2004. If commodity prices significantly decrease, we may modify our capital expenditure plans.

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.

Working Capital

We maintain access to funds that may be needed to meet seasonal requirements through our credit facilities described above. We had positive working capital of $5.2 million at the end of 2003 and $1.6 million at the end of 2002. Current assets increased by 32% in 2003 and current liabilities increased 28%. The increase in current assets at December 31, 2003 was due primarily to increases in accounts receivable and gas-in-storage inventories. The increase in accounts receivable was caused by higher gas prices realized for sales made at the end of 2003, as compared to the end of 2002. Current gas-in-storage increased due to injections made during the summer of 2003 for anticipated use during the 2003-2004 heating season. The increase in current liabilities was due to an increase in accounts payable related to both amounts owed other interest owners for their share of gas and oil sales collected by us and to our increased level of capital investments in our E&P segment.

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. We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis. Under these rules, 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 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. 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, 2003, 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. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the disclosure 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 engage the services of an independent petroleum consulting firm to review reserves as estimated by our reservoir engineers.

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 understands the majority of the oil and natural gas industry did not change accounting and disclosures for mineral interest use rights (leasehold acquisition costs) upon the implementation of FAS 141 and 142. However, an interpretation of FAS 141 and 142 is being considered as to whether mineral interest use rights in gas and oil properties are intangible assets. Under this interpretation mineral interest use rights for both undeveloped and developed leaseholds would be classified as intangible assets, separate from gas and oil properties. The classification as an intangible asset would not affect how these items are accounted for under the full cost method of accounting with respect to the calculation of depreciation, depletion and amortization or the calculation of the ceiling test of gas and oil properties. This interpretation would not affect our results of operations or cash flows. At December 31, 2003 and 2002, the Company had undeveloped leasehold of approximately \$16.9 million and \$8.7 million, respectively, that would be classified as “intangible undeveloped leasehold” if this interpretation were applied. Southwestern also had developed leasehold of approximately \$9.3 million and \$4.5 million at December 31, 2003 and 2002, respectively, that would be classified as “intangible developed leasehold” if it applied the interpretation currently being considered. The portion of developed leasehold that would be reclassified represents the costs of developed leaseholds acquired or transferred to the full cost pool subsequent to June 30, 2001, the effective date of FAS 141. Additionally, FAS 142 requires that certain disclosures be made for all intangible assets. The Company has not made the disclosures set forth under FAS 142 related to the use rights of mineral interests. Southwestern will continue to classify the use rights of mineral interests in gas and oil properties as gas and oil properties until further guidance is provided.

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. 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 utilize market-based quotes from our hedge counterparties to value these open positions. 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. 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 regulatory commission has not required any unbundling of services, although large industrials are free to contract for their own gas supply. There are no regulations relating to unbundling of services currently anticipated; 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 2003, the discount rate assumed is 6.25% and the expected return assumed is 9.0%. This compares to a discount rate of 6.75% and an expected return of 9.0% used in 2002.

Using the assumed rates discussed above, we recorded pension expense of \$3.3 million in 2003 and \$0.9 million in 2002. We reflected a pension liability of \$0.9 million at December 31, 2003 and \$5.6 million at December 31, 2002. During 2003, we also funded \$3.0 million to our pension plan. In 2004, we expect to fund \$2.4 million to our pension plans. Assuming a 1% change in the 2003 rates (lower discount rate and lower rate of return), we would have recorded pension expense of \$4.3 million in 2003.

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 10.4 Bcf at \$3.33 at December 31, 2003 and 10.1 Bcf at \$3.05 at December 31, 2002.

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. Declines 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;
- 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;
- changing market conditions and prices (including regional basis differentials);
- the comparative cost of alternative fuels;
- 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 DISCLOSURE ABOUT MARKET RISKS

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. 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.

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, 2003. 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, 2003 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
	2004	2005	2006	2007	2008	Thereafter	Total	12/31/03
	($ in millions)							
Fixed Rate	$ —	$ 125.0	$ —	$ —	$ —	$ 100.0	$ 225.0	$ 236.2
Average Interest Rate	—	6.70%	—	—	—	7.46%	7.04%	—
Variable Rate	$ —	$ —	$ —	$ 53.8	$ —	$ —	$ 53.8	$ 53.8
Average Interest Rate	—	—	—	2.65%	—	—	2.65%	—

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 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. 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, 2003, the fair value of these financial instruments was an $18.9 million liability.

	Expected Maturity Date	
	2004	2005
Production and Marketing		
Natural Gas		
Swaps with a fixed-price receipt		
Contract volume (Bcf)	8.0	6.0
Weighted average price per Mcf	$ 4.21	$ 4.67
Fair value (in millions)	$ (10.3)	$ (0.5)
Price collars		
Contract volume (Bcf)	23.6	1.0
Weighted average floor price per Mcf	$ 3.85	$ 4.50
Fair value of floor (in millions)	$ 1.8	$ 0.3
Weighted average ceiling price per Mcf	$ 6.48	$ 8.00
Fair value of ceiling (in millions)	$ (11.5)	$ (0.3)
Swaps with a fixed-price payment		
Contract volume (Bcf)	0.5	—
Weighted average price per Mcf	$ 5.05	$ —
Fair value (in millions)	$ 0.3	$ —
Oil		
Swaps with a fixed-price receipt		
Contract volume (MBbls)	426	—
Weighted average price per Bbl	$ 28.39	$ —
Fair value (in millions)	$ (0.8)	$ —
Natural Gas Purchases		
Swaps with a fixed-price payment		
Contract volume (Bcf)	3.8	—
Weighted average price per Mcf	$ 5.34	$ —
Fair value (in millions)	$ 2.1	$ —

At December 31, 2003, the Company had outstanding fixed-price basis differential swaps on 9.1 Bcf of 2004 gas production that did not qualify for hedge accounting treatment. The fair value of these differential swaps was an asset of $1.1 million at December 31, 2003.

At December 31, 2002, the Company had outstanding natural gas price swaps on total notional volumes of 13.3 Bcf in 2003 and 7.2 Bcf in 2004 for which the Company received fixed prices ranging from $2.75 to $4.30 per MMBtu. Outstanding oil price swaps on 240 MBbls were in place that yielded the Company an average price of $25.40 per barrel. At December 31, 2002, the Company also had outstanding natural gas price swaps on total notional gas purchase volumes of 2.7 Bcf in 2003 for which the Company paid an average fixed price of $3.42 per Mcf.

At December 31, 2002, the Company had collars in place on 15.9 Bcf in 2003 and 8.0 Bcf in 2004 of gas production. The 15.9 Bcf in 2003 had an average floor and ceiling price of $3.16 and $4.84 per MMBtu, respectively. The 8.0 Bcf in 2004 had an average floor and ceiling price of $3.50 and $4.65 per MMBtu, respectively.

Subsequent to December 31, 2003 and prior to February 23, 2004, we entered into additional derivative contracts to hedge gas and oil production sales. Price collar hedges on 1.0 Bcf of 2005 gas production sales have an average floor of $4.50 per Mcf and an average ceiling of $8.35 per Mcf. Fixed price swaps on 3.0 Bcf of 2005 gas production will yield $4.93 per Mcf.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF MANAGEMENT

Management is responsible for the preparation and integrity of our financial statements. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States consistently applied, and necessarily include some amounts that are based on management's best estimates and judgment.

We maintain a system of internal accounting and administrative controls and an ongoing program of internal audits that management believes provide reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with management's authorization. Our financial statements have been audited by our independent auditors, PricewaterhouseCoopers LLP. In accordance with auditing standards generally accepted in the United States, the independent auditors considered our internal controls over financial reporting solely for the purpose of determining the nature, timing, and extent of auditing procedures necessary for expressing their opinion on the financial statements.

The Audit Committee of the Board of Directors, composed solely of outside directors, meets with management, internal auditors, and PricewaterhouseCoopers LLP to review planned audit scopes and results and to discuss other matters affecting internal accounting controls and financial reporting. The independent auditors have direct access to the Audit Committee and periodically meet with the Audit Committee without management representatives present.

REPORT OF INDEPENDENT AUDITORS

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows and changes in shareholders' equity and comprehensive income (loss) present fairly, in all material respects, the financial position of Southwestern Energy Company and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, 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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 8 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivatives to adopt the requirements of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities." 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."

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 9, 2004

STATEMENTS OF OPERATIONS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2003	2002	2001
	(in thousands, except share/per share amounts)		
Operating revenues:			
Gas sales	$ 256,467	$ 198,108	$ 248,952
Gas marketing	43,313	41,709	71,839
Oil sales	14,180	14,340	16,932
Gas transportation and other	13,441	7,345	7,204
	327,401	261,502	344,927
Operating costs and expenses:			
Gas purchases - utility	52,585	48,388	68,161
Gas purchases - marketing	39,428	37,927	68,010
Operating expenses	37,377	38,154	39,035
General and administrative expenses	33,102	26,446	25,073
Depreciation, depletion and amortization	55,948	53,992	52,899
Taxes, other than income taxes	11,619	10,090	9,080
	230,059	214,997	262,258
Operating income	97,342	46,505	82,669
Interest expense:			
Interest on long-term debt	17,722	21,664	23,920
Other interest charges	1,381	1,285	1,374
Interest capitalized	(1,792)	(1,483)	(1,595)
	17,311	21,466	23,699
Other income (expense)	797	(566)	(799)
Income before income taxes, minority interest and accounting change	80,828	24,473	58,171
Minority interest in partnership	(2,180)	(1,454)	(930)
Income before income taxes and accounting change	78,648	23,019	57,241
Provision for income taxes			
Current	—	—	—
Deferred	28,896	8,708	21,917
	28,896	8,708	21,917
Income before accounting change	49,752	14,311	35,324
Cumulative effect of adoption of accounting principle	(855)	—	—
Net Income	$ 48,897	$ 14,311	$ 35,324
Basic Earnings per share:			
Income before accounting change	$1.49	$0.57	$1.40
Cumulative effect of adoption of accounting principle	(0.03)	—	—
Net Income	$1.46	$0.57	$1.40
Diluted Earnings per share:			
Income before accounting change	$1.45	$0.55	$1.38
Cumulative effect of adoption of accounting principle	(0.02)	—	—
Net Income	$1.43	$0.55	$1.38
Weighted average common shares outstanding:			
Basic	33,396,052	25,226,580	25,198,105
Diluted	34,237,934	26,052,238	25,601,110

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

BALANCE SHEETS

Southwestern Energy Company and Subsidiaries

	December 31, 2003	December 31, 2002
	(in thousands)	
ASSETS		
Current assets		
Cash	$ 1,277	$ 1,690
Accounts receivable	58,543	42,115
Inventories, at average cost	31,418	24,735
Under-recovered purchased gas costs	1,107	—
Hedging asset - FAS 133	3,693	3,130
Other	4,272	4,468
Total current assets	100,310	76,138
Investments	13,840	15,287
Property, plant and equipment, at cost		
Gas and oil properties, using the full cost method, including $38,958,000 in 2003 and $25,494,000 in 2002 excluded from amortization	1,201,917	1,030,300
Gas distribution systems	203,793	197,473
Gas in underground storage	33,256	32,395
Other	30,038	31,391
	1,469,004	1,291,559
Less: Accumulated depreciation, and amortization	706,720	659,398
	762,284	632,161
Other assets	14,276	16,576
	$ 890,710	$ 740,162
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 54,186	$ 29,881
Taxes payable	5,692	5,213
Interest payable	2,338	2,513
Customer deposits	5,277	4,999
Hedging liability - FAS 133	20,997	20,409
Regulatory liability - hedges	2,137	3,130
Over-recovered purchased gas costs	—	5,697
Other	4,441	2,715
Total current liabilities	95,068	74,557
Long-term debt	278,800	342,400
Other liabilities		
Deferred income taxes	147,295	116,591
Other	15,859	16,671
	163,154	133,262
Commitments and contingencies		
Minority interest in partnership	12,127	12,455
Shareholders' equity		
Common stock, $0.10 par value; authorized 75,000,000 shares, issued 37,225,584 shares in 2003 and 27,738,084 shares in 2002	3,723	2,774
Additional paid-in capital	123,519	19,130
Retained earnings	246,885	197,988
Accumulated other comprehensive income (loss)	(12,520)	(17,358)
Less: Common stock in treasury, at cost, 1,307,995 shares in 2003 and 1,793,456 shares in 2002	(14,571)	(19,981)
Unamortized cost of restricted shares issued under stock incentive plan, 421,617 shares in 2003 and 498,123 shares in 2002	(5,475)	(5,065)
	341,561	177,488
	$ 890,710	$ 740,162

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

STATEMENTS OF CASH FLOWS
Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2003	2002	2001
		(in thousands)	
Cash flows from operating activities			
Net income	$ 48,897	$ 14,311	$ 35,324
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	58,788	56,399	54,505
Deferred income taxes	28,896	8,708	21,917
Ineffectiveness of cash flow hedges	(636)	1,121	—
Equity in (income) loss of NOARK partnership	(1,053)	251	1,484
Gain on sale of other property, plant and equipment	(2,991)	—	—
Minority interest in partnership	(429)	(1,015)	(533)
Cumulative effect of adoption of accounting principle	855	—	—
Change in assets and liabilities:			
Accounts receivable	(16,427)	648	34,278
Under/over-recovered gas costs	(6,804)	(2,487)	21,126
Inventories	(6,683)	1,871	(9,606)
Accounts payable	4,693	(2,883)	(12,660)
Other current assets and liabilities	1,993	650	(1,252)
Net cash provided by operating activities	109,099	77,574	144,583
Cash flows from investing activities			
Capital expenditures	(168,172)	(92,062)	(106,060)
Sale of natural gas and oil properties	—	26,415	—
Distribution from (investment in) NOARK partnership	2,500	—	(1,449)
Proceeds from the sale of property, plant and equipment	3,649	—	—
Increase in gas stored underground	(860)	(349)	(4,179)
Other items	1,227	1,527	826
Net cash used in investing activities	(161,656)	(64,469)	(110,862)
Cash flows from financing activities			
Issuance of common stock	103,085	—	—
Payments on revolving long-term debt	(273,000)	(204,100)	(248,500)
Borrowings under revolving long-term debt	209,400	196,500	202,500
Change in bank drafts outstanding	7,988	(9,880)	—
Proceeds from exercise of common stock options	4,671	1,955	—
Contribution from minority interest owner in partnership	—	469	13,534
Net cash provided by (used in) financing activities	52,144	(15,056)	(32,466)
Increase (decrease) in cash	(413)	(1,951)	1,255
Cash at beginning of year	1,690	3,641	2,386
Cash at end of year	$ 1,277	$ 1,690	$ 3,641

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

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

Southwestern Energy Company and Subsidiaries

	Common Stock Shares Issued	Common Stock Amount	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Treasury Stock	Unamortized Restricted Stock Awards	Total
					(in thousands)			
Balance at December 31, 2000	27,738	$ 2,774	$ 20,220	$ —	$ 148,353	$ (28,485)	$ (1,571)	$ 141,291
Comprehensive income:								
Transition adjustment for adoption of FAS 133	—	—	—	(36,963)	—	—	—	(36,963)
Net income	—	—	—	—	35,324	—	—	35,324
Change in value of derivatives	—	—	—	42,726	—	—	—	42,726
Total comprehensive income	—	—	—	—	—	—	—	41,087
Exercise of stock options	—	—	(31)	—	—	93	—	62
Issuance of restricted stock	—	—	(446)	—	—	3,247	(2,801)	—
Cancellation of restricted stock	—	—	21	—	—	(51)	30	—
Amortization of restricted stock and other	—	—	—	—	—	—	646	646
Balance at December 31, 2001	27,738	2,774	19,764	5,763	183,677	(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	(17,358)	197,988	(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	$ (12,520)	$ 246,885	$ (14,571)	$ (5,475)	$ 341,561

The accompanying notes are an integral part of these 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,		
	2003	2002	2001
		(in thousands)	
Balance, beginning of year	$ (17,358)	$ 5,763	$ —
Cumulative effect of adoption of FAS 133	—	—	(36,963)
Current period reclassification to earnings	24,667	4,735	22,874
Current period change in derivative instruments	(22,640)	(24,498)	19,852
Current period change in pension liability	2,811	(3,358)	—
Balance, end of year	$ (12,520)	$ (17,358)	$ 5,763

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
December 31, 2003, 2002 and 2001

(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, 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, 2003 the estimated fair value of the minority ownership position of the partnership does not exceed the minority interest of $12.1 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, 2003, 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, 2003 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.

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 understands the majority of the oil and natural gas industry did not change accounting and disclosures for mineral interest use rights (leasehold acquisition costs) upon the implementation of FAS 141 and 142. However, an interpretation of FAS 141 and 142 is being considered as to whether mineral interest use rights in gas and oil properties are intangible assets. Under this interpretation mineral interest use rights for both undeveloped and developed leaseholds would be classified as intangible assets, separate from gas and oil properties. The classification as an intangible asset would not affect how these items are accounted for under the full cost method of accounting with respect to the calculation of depreciation, depletion and amortization or the calculation of the ceiling test of gas and oil properties. This interpretation would not affect our results of operations or cash flows. At December 31, 2003 and 2002, the Company had undeveloped leasehold of approximately $16.9 million and $8.7 million, respectively, that would be classified as "intangible undeveloped leasehold" if this interpretation were applied. Southwestern also had developed leasehold of approximately $9.3 million and $4.5 million at December 31, 2003 and 2002, respectively, that would be classified as "intangible developed leasehold" if it applied the interpretation currently being considered. The portion of developed leasehold that would be reclassified represents the costs of developed leaseholds acquired or transferred to the full cost pool subsequent to June 30, 2001, the effective date of FAS 141. Additionally, FAS 142 requires that certain disclosures be made for all intangible assets. The Company has not made the disclosures set forth under FAS 142 related to the use rights of mineral interests. Southwestern will continue to classify the use rights of mineral interests in gas and oil properties as gas and oil properties until further guidance is provided.

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 1.9% to 6.0%.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 4 to 34 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 gas prices 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. 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 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 and 2001 assuming that this accounting standard had been adopted at such time. The following table summarizes the Company's 2003 activity related to asset retirement obligations:

	2003 (in thousands)
Asset Retirement Obligation at January 1	$7,700
Accretion of Discount	303
Obligations Incurred	803
Obligations Settled	(852)
Revisions from Changes in Expected Cash Flows	(410)
Asset Retirement Obligation at December 31	$ 7,544
Current Liability	184
Long-term Liability	7,360
Total Asset Retirement Obligation at December 31	$ 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, 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. At December 31, 2002, the Company had overproduction of 1.3 Bcf valued at $3.9 million and underproduction of 1.5 Bcf valued at $4.3 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, 2003 was $122.7 million with expiration dates in 2020 through 2023.

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 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. The Company had options for 222,030 shares with an average exercise price of $21.93 outstanding at December 31, 2003, options for 1,228,744 shares of common stock with a weighted average exercise price of $13.36 per share at December 31, 2002, and options for 1,006,234 shares of common stock with a weighted average exercise price of $13.83 per share at December 31, 2001, that were not included in the calculation of diluted shares because they would have had an anti-dilutive effect. The remaining 2,304,880 options at December 31, 2003, with a weighted average exercise price of $9.79, 1,481,074 options at December 31, 2002, with a weighted average exercise price of $7.53, and 1,665,952 options at December 31, 2001, with a weighted average exercise price of $7.43 were included in the calculation of diluted shares. Restricted stock shares included in the calculation of diluted shares were 175,364, 498,123 and 416,537 for 2003, 2002 and 2001, respectively.

Guarantees

During 2002, the Company adopted 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.

Beginning in 2003, 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. As the Company's issuance of guarantees is limited, the liability recognition provisions of the standard are not expected to have a material impact upon the Company's financial position or results of operations.

Accounting for Stock-Based Compensation

At December 31, 2003, 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,		
	2003	2002	2001
Net income, as reported	$48,897	$ 14,311	$ 35,324
Add back: Amortization of restricted stock	1,083	781	399
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(2,245)	(1,798)	(1,350)
Pro forma net income	$ 47,735	$ 13,294	$ 34,373
Earnings per share:			
Basic-as reported	$ 1.46	$ 0.57	$ 1.40
Basic-pro forma	1.43	0.53	1.36
Diluted-as reported	1.43	0.55	1.38
Diluted-pro forma	1.40	0.51	1.34

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 47.1% for 2003, 45.6% for 2002 and 46.4% for 2001; risk-free interest rate of 3.7% for 2003, 3.4% for 2002 and 4.8% for 2001; and expected lives of 6 years for all option grants. The fair values of the option grants for each of the years 2003, 2002 and 2001 were $2.4 million, $1.9 million and $0.9 million, respectively.

(2) DEBT

Debt balances as of December 31, 2003 and 2002 consisted of the following:

	2003	2002
	(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 (2.67% at December 31, 2003) unsecured revolving credit arrangements	53,800	117,400
Total long-term debt	$ 278,800	$ 342,400

In January 2004, the Company arranged a new $300 million three-year unsecured revolving credit facility with a group of banks to replace its previous $125 million credit facility that was scheduled to expire in July 2004. The Company also has access to an additional $15 million of borrowing capacity under a separate three-year unsecured credit facility that was entered into at the same time. The interest rate on each of the new credit facilities is calculated based upon our debt rating and is currently 125 basis points over LIBOR. The revolving credit facilities contain covenants which impose certain restrictions on the Company. Under the credit agreements, 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. The Company was in compliance with its debt agreements at December 31, 2003.

There are no aggregate maturities of long-term debt for each of the years ending December 31, 2004, 2006 and 2008. For each of the years ended December 31, 2005 and 2007, the aggregate maturities are $125.0 million and $53.8 million, respectively. Total interest payments were $17.3 million in 2003, $21.5 million in 2002 and $24.4 million in 2001.

(3) INCOME TAXES

The provision for income taxes included the following components:

	2003	2002	2001
		(in thousands)	
Federal:			
Current	$ —	$ —	$ —
Deferred	26,507	8,048	19,461
State:			
Current	—	—	—
Deferred	2,506	779	2,575
Investment tax credit amortization	(117)	(119)	(119)
Provision for income taxes	$ 28,896	$ 8,708	$ 21,917

The provision for income taxes was an effective rate of 36.7% in 2003, 37.8% in 2002 and 38.3% in 2001. 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:

	2003	2002 (in thousands)	2001
Expected provision at federal statutory rate of 35%	$ 27,527	$ 8,055	$ 20,034
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	1,629	506	1,674
Other	(260)	147	209
Provision for income taxes	$ 28,896	$ 8,708	$ 21,917

The components of the Company's net deferred tax liability as of December 31, 2003 and 2002 were as follows:

	2003	2002
	(in thousands)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$ 182,081	$ 156,208
Stored gas	6,448	4,337
Book over tax basis in partnerships	12,851	11,324
Other	8,458	4,421
	209,838	176,290
Deferred tax assets:		
Accrued compensation	$ 556	$ 525
Alternative minimum tax credit carryforward	3,026	3,026
Accrued pension costs	318	2,102
Cash flow hedges - FAS 133	7,338	8,764
Asset retirement obligations - FAS 143	2,525	—
Net operating loss carryforward	46,456	45,952
Other	3,282	406
	63,501	60,775
Net deferred tax liability	$ 146,337	$ 115,515

There were no income tax payments in 2003, 2002 and 2001. The Company's net operating loss carryforward at December 31, 2003, was $122.7 million with expiration dates in 2020 through 2023. The Company also had an alternative minimum tax credit carryforward of $3.0 million and a statutory depletion carryforward of $4.1 million at December 31, 2003.

(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, 2003 and 2002:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
	(in thousands)			
Change in benefit obligations:				
Benefit obligation at January 1	$ 54,694	$ 60,925	$ 3,156	$ 2,099
Service cost	2,170	1,967	139	90
Interest cost	3,659	3,655	238	170
Participant contributions	—	—	82	76
Actuarial loss (gain)	3,820	(6,762)	668	958
Benefits paid	(3,678)	(5,091)	(234)	(237)
Benefit obligation at December 31	$ 60,665	$ 54,694	$ 4,049	$ 3,156

Change in plan assets:				
Fair value of plan assets at January 1	$ 41,973	$ 59,010	$ 732	$ 672
Actual return on plan assets	10,659	(11,959)	(24)	(7)
Employer contributions	3,002	13	282	228
Participant contributions	—	—	82	76
Benefit payments	(3,678)	(5,091)	(234)	(237)
Amount transferred	—	—	—	—
Fair value of plan assets at December 31	$ 51,956	$ 41,973	$ 838	$ 732
Funded status:				
Funded status at December 31	$ (8,709)	$ (12,721)	$ (3,211)	$ (2,424)
Unrecognized net actuarial loss	8,747	12,643	1,891	1,249
Unrecognized prior service cost	3,610	4,056	—	—
Unrecognized transition obligation	—	—	774	860
Net amount recognized	$ 3,648	$ 3,978	$ (546)	$ (315)

The Company uses a December 31 measurement date for all of its plans. Amounts recognized in the balance sheets as of December 31, 2003 and 2002 consist of the following:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
	(in thousands)			
Prepaid (accrued) benefit cost	$ 3,648	$ 3,978	$ (546)	$ (315)
Minimum pension liability	(4,532)	(9,580)	—	—
Intangible asset	3,668	4,119	—	—
Accumulated other comprehensive loss (pre-tax)	864	5,461	—	—
Net amount recognized	$ 3,648	$ 3,978	$ (546)	$ (315)

The change in accumulated other comprehensive loss related to the pension plans was income of $4.5 million ($2.8 million after tax) for the year ended December 31, 2003, and a loss of $5.5 million ($3.4 million after tax) for the year ended December 31, 2002. Included in accumulated other comprehensive loss at December 31, 2003 and 2002 was a $0.9 million loss ($0.5 million net of tax), and a $5.5 million loss ($3.4 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, 2003 and 2002 as follows:

	2003	2002
	(in thousands)	
Projected benefit obligation	$60,665	$54,694
Accumulated benefit obligation	52,766	47,364
Fair value of plan assets	51,956	41,973

Net periodic pension and other postretirement benefit costs include the following components for 2003, 2002 and 2001:

	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	2003	2002	2001
	(in thousands)					
Service cost	$ 2,171	$ 1,967	$ 1,318	$ 139	$ 90	$ 71
Interest cost	3,659	3,655	4,133	238	170	138
Expected return on plan assets	(3,608)	(5,165)	(5,829)	(36)	(41)	(34)
Amortization of transition obligation	—	—	(36)	86	86	86
Recognized net actuarial (gain) loss	664	7	(97)	87	79	19
Amortization of prior service cost	446	457	451	—	—	—
	$ 3,332	$ 921	$ (60)	$ 514	$ 384	$ 280

The Company's pension plans provide for benefits on a "cash balance" basis. 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, 2003 and 2002 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Discount rate	6.25%	6.75%	6.25%	6.75%
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 2003 and 2002 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Discount rate	6.75%	7.00%	6.75%	7.00%
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 2003 and 2002:

	2003	2002
Health care cost trend assumed for next year	11%	12%
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	$ 50	$ (42)
Effect on postretirement benefit obligation	$ 502	$ (425)

The Company’s pension plan weighted-average asset allocations at December 31, 2003, and 2002, by asset category are as follows:

	2003	2002
Asset Category:		
Equity securities	65%	71%
Debt securities	33%	28%
Cash equivalents	2%	1%
Total	100%	100%

Assets of the postretirement benefit plans were invested 100% in debt securities for 2003 and 2002.

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, 2003, 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.

The Company expects to contribute $2.4 million to its pension plan and $0.4 million to its other postretirement benefit plans in 2004.

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

	Pension Benefits	Other Benefits
	(in thousands)	
2004	$2,911	$181
2005	2,945	186
2006	3,761	190
2007	4,495	216
2008	3,982	256
Years 2009-2013	25,886	1,506

(5) NATURAL GAS AND OIL PRODUCING ACTIVITIES

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:

	2003	2002	2001
		(in thousands)	
Sales	$ 176,245	$ 122,207	$ 153,937
Production (lifting) costs	(24,993)	(25,514)	(24,393)
Depreciation, depletion and amortization	(49,553)	(47,680)	(46,530)
	101,699	49,013	83,014
Income tax expense	(37,306)	(18,474)	(31,519)
Results of operations	$ 64,393	$ 30,539	$ 51,495

The results of operations shown above exclude overhead 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 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
Proved property acquisition costs	$ 3,240	$ 3,481	$ 7,323
Unproved property acquisition costs	17,484	4,984	4,482
Exploration costs	20,862	24,552	23,490
Development costs	129,028	51,818	63,103
Capitalized costs incurred	$ 170,614	$ 84,835	$ 98,398
Full cost pool amortization per Mcf equivalent	$ 1.17	$ 1.16	$ 1.14

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $1.8 million, $1.5 million and $1.6 million during 2003, 2002 and 2001, 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 $10.6 million, $9.5 million and $8.3 million during 2003, 2002 and 2001, 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, 2003 and 2002:

	2003	2002
	(in thousands)	
Proved properties	$ 1,162,959	$ 1,004,806
Unproved properties	38,958	25,494
Total capitalized costs	1,201,917	1,030,300
Less: Accumulated depreciation, depletion and amortization	593,017	549,419
Net capitalized costs	$ 608,900	$ 480,881

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2003. Of the total, approximately $16.7 million represents costs of wells in progress at December 31, 2003, and approximately $11.0 million is related to undeveloped leasehold costs in new venture areas. 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.

	2003	2002	2001	Prior	Total
			(in thousands)		
Property acquisition costs	$14,377	$ 1,608	$ 1,235	$ 1,584	$18,804
Exploration and development costs	11,259	3,667	131	2,195	17,252
Capitalized interest	810	524	239	1,329	2,902
	$26,446	$ 5,799	$ 1,605	$ 5,108	$38,958

(6) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2003, 2002 and 2001:

	2003		2002		2001	
	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	374,614	6,784	355,813	7,704	331,754	8,130
Revisions of previous estimates	(16,668)	186	1,110	234	(21,598)	(979)
Extensions, discoveries and other additions	136,261	1,193	73,803	553	77,187	1,272
Production	(37,967)	(531)	(35,972)	(682)	(35,477)	(719)
Acquisition of reserves in place	808	48	6,538	15	4,325	21
Disposition of reserves in place	(32)	(5)	(26,678)	(1,040)	(378)	(21)
Proved reserves, end of year	457,016	7,675	374,614	6,784	355,813	7,704
Proved developed reserves:						
Beginning of year	286,276	5,633	281,461	6,429	270,830	7,100
End of year	369,867	6,719	286,276	5,633	281,461	6,429

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. with respect to 2003 and 2002, and by K & A Energy Consultants, Inc. with respect to 2001.

Following is the standardized measure relating to proved gas and oil reserves at December 31, 2003, 2002 and 2001:

	2003	2002 (in thousands)	2001
Future cash inflows	$ 2,914,824	$ 1,951,454	$ 1,095,843
Future production costs	(644,014)	(466,742)	(313,357)
Future development costs	(69,668)	(62,206)	(57,136)
Future income tax expense	(647,605)	(420,336)	(182,103)
Future net cash flows	1,553,537	1,002,170	543,247
10% annual discount for estimated timing of cash flows	(837,185)	(500,571)	(235,087)
Standardized measure of discounted future net cash flows	$ 716,352	$ 501,599	$ 308,160

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. 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 2003, 2002 and 2001:

	2003	2002 (in thousands)	2001
Standardized measure, beginning of year	$ 501,599	$ 308,160	$ 895,142
Sales and transfers of gas and oil produced, net of production costs	(151,793)	(96,693)	(129,544)
Net changes in prices and production costs	182,019	284,277	(979,522)
Extensions, discoveries, and other additions, net of future production and development costs	338,374	137,105	102,832
Acquisition of reserves in place	1,759	11,269	5,406
Revisions of previous quantity estimates	(34,637)	4,870	(24,966)
Accretion of discount	69,413	39,451	133,136
Net change in income taxes	(85,441)	(106,177)	349,862
Changes in production rates (timing) and other	(104,941)	(80,663)	(44,186)
Standardized measure, end of year	$ 716,352	$ 501,599	$ 308,160

(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. 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 NOARK totaled $13.8 million at December 31, 2003, and $15.2 million at December 31, 2002. See Note 11 for further discussion of NOARK's funding requirements and the Company's investment in NOARK.

The Company recorded pre-tax income of $1.1 million in 2003 and pre-tax losses of $0.3 million and $1.5 million for 2002 and 2001, respectively, for its share of NOARK's results of operations. The pre-tax gain in 2003 included a gain of $1.3 million recognized on the sale of a 28-mile portion of NOARK's pipeline 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:

Cash, 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, 2003 and 2002 were as follows:

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash	$ 1,276	$ 1,276	$ 1,690	$ 1,690
Customer deposits	$ 5,277	$ 5,277	$ 4,999	$ 4,999
Long-term debt	$ 278,800	$ 290,040	$ 342,400	$ 340,048
Commodity and interest hedges asset (liability)	$ (17,778)	$ (17,778)	$ (20,875)	$ (20,875)

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, 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 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, 2002, the Company recorded hedging assets of $3.1 million, hedging liabilities of $24.0 million, a regulatory liability of $3.1 million related to its utility gas purchase hedges, and a net of tax loss to other comprehensive income (loss) of $14.0 million. The change in accumulated other comprehensive loss related to derivatives was income of $3.2 million ($2.0 million after tax) for the year ended December 31, 2003, a loss of $31.9 million ($19.8 million after tax) for the year ended December 31, 2002 and income of $9.3 million ($5.8 million after tax), including the cumulative effect of adoption of FAS 133, for the year ended December 31, 2001. The Company recorded 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 in 2003, the Company recorded a $1.1 million gain related to mark-to-market adjustments on basis differential swaps which did not qualify for hedge treatment. There was no significant ineffectiveness recorded in 2001. 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 or 2001. 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, 2003, the Company had outstanding natural gas price swaps on total notional volumes of 8.0 Bcf in 2004 and 6.0 Bcf in 2005 for which the Company will receive fixed prices ranging from $3.79 to $6.48 per MMBtu. Outstanding oil price swaps on 426 MBbls were in place that will yield the Company an average price of $28.39 per barrel. At December 31, 2003, the Company also had outstanding natural gas price swaps on total notional volumes of 4.3 Bcf in 2004 for which the Company will pay an average fixed price of $5.31 per Mcf. At December 31, 2003, the Company had outstanding fixed price basis differential swaps on 9.1 Bcf of 2004 gas production that did not qualify for hedge treatment. There were no basis swaps in 2002 or 2001.

At December 31, 2003, the Company had collars in place on notional volumes of 23.6 Bcf in 2004 and 1.0 Bcf in 2005. The 23.6 Bcf in 2004 had an average floor and ceiling price of $3.85 and $6.48 per MMBtu, respectively. The 1.0 Bcf in 2005 had an average floor and ceiling price of $4.50 and $8.00 per MMBtu, respectively. The Company's price risk management activities reduced revenues by $37.4 million in 2003, $6.1 million in 2002 and $10.3 million in 2001.

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

The Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan) was adopted in February 2000 and provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2000 Plan replaced 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 2000 Plan provides for grants of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock that in the aggregate do not exceed 1,250,000 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 2000 Plan.

The Southwestern Energy Company 2002 Employee Stock Incentive Plan (2002 Plan) was adopted in October 2002 and provides 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 provides for grants of options, stock appreciation rights, shares of phantom stock and shares of restricted stock that in the aggregate do 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 2000 Plan and the 1993 Plan to certain non-officer employees and to certain officers at the time of their hire.

The 2000 Plan awards each non-employee director who is eligible to participate in the plan an annual Director's Option with respect to 8,000 shares of common stock. Previously, 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 2003, 2002 and 2001 and provide information for options outstanding at December 31, 2003:

	2003		2002		2001	
	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	2,709,818	$ 10.17	2,672,186	$ 9.84	2,602,800	$ 9.79
Granted	222,030	21.93	346,010	11.43	170,200	10.13
Exercised	401,605	12.38	247,464	8.39	11,252	7.00
Canceled	3,333	7.44	60,914	10.09	89,562	9.22
Options outstanding at December 31	2,526,910	$ 10.86	2,709,818	$ 10.17	2,672,186	$ 9.84

	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	422,849	$ 6.18	5.9	422,849	$ 6.18
$7.01 - $8.75	668,529	7.41	6.5	668,529	7.41
$8.76 - $13.38	868,252	11.47	6.6	562,519	11.67
$13.39 - $17.50	345,250	14.60	1.8	343,584	14.60
$17.51 - $24.78	222,030	21.93	10.0	—	—
	2,526,910	$ 10.86		1,997,481	$ 9.59

All options are issued at fair market value at the date of grant and expire ten years from the date of grant. 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.

The Company granted 110,038 shares, 233,460 shares and 299,850 shares of restricted stock in 2003, 2002 and 2001, respectively. The fair values of the grants were $2.3 million for 2003, $2.7 million for 2002 and $2.9 million for 2001. Of the 1,096,513 shares granted to date, 433,715 shares vest over a three-year period, 620,248 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 $1.7 million for 2003, $1.3 million for 2002 and $0.6 million for 2001. As of December 31, 2003, 614,733 shares have vested to employees. Restricted shares cancelled in 2003, 2002 and 2001 were 13,142 shares, 6,739 shares and 18,184 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, 2003 and 2002, the principal outstanding for these Notes was $69.0 million and $71.0 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 did not advance any funds to NOARK in 2003 and 2002, and advanced $1.4 million in 2001. 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, the Company's gas distribution subsidiary has transportation contracts for firm capacity of 66.9 MMcfd on NOARK's integrated pipeline system. These contracts are renewable year-to-year until terminated by 180 days' notice.

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, 2003, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $1,224,000 in 2004, $1,196,000 in 2005, $987,000 in 2006, $462,000 in 2007, $449,000 in 2008 and $1,808,000 thereafter. Total rent expense for all operating leases was $1,196,000, $811,000 and $706,000 in 2003, 2002 and 2001, 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. Additionally, the E&P segment has a commitment to a third party for demand transportation charges. At December 31, 2003, future payments under these non-cancelable demand contracts are $11,396,000 in 2004, $3,326,000 in 2005, $2,866,000 in 2006, $1,449,000 in 2007, $1,449,000 in 2008 and $3,938,000 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
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	170,886(3)	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
2001					
Revenues from external customers	$ 126,006	$ 147,082	$ 71,839	$ —	$344,927
Intersegment revenues	27,931	200	118,486	448	147,065
Operating income	69,340	10,346	2,703	280	82,669
Depreciation, depletion and amortization expense	46,530	6,163	111	95	52,899
Interest expense(1)	18,238	4,413	34	1,014	23,699
Provision (benefit) for income taxes(1)	19,164	2,505	996	(748)	21,917
Assets	526,346	169,931	8,026	38,820(2)	743,123
Capital expenditures	98,964(4)	5,347	—	1,749	106,060

(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) E&P capital expenditures for 2003 include $12.0 million of accrued expenditures.

(4) Includes $0.5 million in 2002 and $13.5 million in 2001 funded by the owner of the minority interest in Overton partnership.

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, 2003 and 2002:

	Mar 31	June 30	Sept 30	Dec 31
	(in thousands, except per share amounts)			
	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
	2002			
Operating revenues	$ 81,658	$ 56,004	$ 51,091	$ 72,749
Operating income	16,839	8,900	7,994	12,772
Net income	6,715	1,770	1,274	4,552
Basic earnings per share	0.26	0.07	0.05	0.18
Diluted earnings per share	0.26	0.07	0.05	0.17

(14) NEW ACCOUNTING STANDARDS

During May 2003, the FASB issued Statement on Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" (FAS 150). FAS 150 establishes standards regarding the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. FAS 150 became effective for the Company starting in the quarter ended September 30, 2003. The adoption of this standard did not have any impact on the Company's financial position or results of operations.

On January 17, 2003, the FASB issued FASB Interpretation No. 46, “Consolidation of Variable Interest Entities, an interpretation of ARB 51” (FIN 46). The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. FIN 46, as amended, is effective for periods ending after December 15, 2003 (December 31, 2003 for the Company). The adoption of this standard did not have any impact on the Company's financial position or results of operations.

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

On June 20, 2002, our Board of Directors determined, upon the recommendation of its Audit Committee, to appoint PricewaterhouseCoopers LLP as our independent public accountants, replacing Arthur Andersen LLP, which we dismissed on the same date. This determination followed our decision, announced on March 29, 2002, to seek proposals from other independent public accountants to audit our financial statements for the fiscal year ended December 31, 2002.

The audit report of Andersen on the consolidated financial statements of Southwestern and subsidiaries as of and for the fiscal year ended December 31, 2001 did not contain any adverse opinion or disclaimer of opinion, nor was it qualified or modified as to uncertainty or audit scope. In addition, there were no modifications as to accounting principles except that the audit report of Andersen contained an explanatory paragraph with respect to the change in the method of accounting for derivative instruments effective January 1, 2001, as required by the Financial Accounting Standards Board.

During 2001 and through June 20, 2002, there were no disagreements between us and Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to Andersen's satisfaction, would have caused Andersen to make reference to the subject matter of the disagreement in connection with their reports; and there were no reportable events, as described in Item 304(a) (1) (v) of Regulation S-K.

Southwestern provided Andersen with a copy of the foregoing disclosures and Andersen provided us with a letter dated June 20, 2002, stating that it had no basis for disagreement with such statements. This letter was filed as Exhibit 16.1 to a current report on Form 8-K dated June 20, 2002, filed by us with the SEC.

During 2001 and through June 20, 2002, we did not consult PricewaterhouseCoopers with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on our consolidated financial statements, or any other matters or reportable events listed in Items 304(a) (2) (i) and (ii) of Regulation S-K.

ITEM 9A. CONTROLS AND PROCEDURES

Our Chief Executive Officer and our Chief Financial Officer evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Our disclosure controls and procedures are the controls and other procedures that we designed to ensure that we record, process, summarize, and report in a timely manner the information we must disclose in reports that we file with the SEC. Our disclosure controls and procedures include our internal accounting controls. Based on the evaluation of our Chief Executive Officer and our Chief Financial Officer, our disclosure controls and procedures are effective. There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of our evaluation.

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 12, 2004, or the 2004 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 2004 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.

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.

ITEM 11. EXECUTIVE COMPENSATION

The 2004 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 2004 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The 2004 Proxy Statement is hereby incorporated by reference for the purpose of providing information about security ownership of certain beneficial owners and our management. 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 2004 Proxy Statement is hereby incorporated by reference for the purpose of providing information about related transactions. Refer to the section "Share Ownership of Management, Directors and Nominees" and "Equity Compensation Plans" for information about transactions with our executive officers, directors or management.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The 2004 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 Public Accountants” for information concerning fees paid to our principal accountant and the audit committee’s pre-approval policies and procedures.

PART IV

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

(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.

(b) Current Reports on Form 8-K:

Date of Report	Item Number	Financial Statements Required to be Filed
February 19, 2004	9	No
February 19, 2004	12	No
February 11, 2004	5,7	No
January 7, 2004	5,7	No
December 3, 2003	9	No
November 20, 2003	9	No
November 12, 2003	9	No
October 30, 2003	12	No
October 30, 2003	12	No

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: February 25, 2004

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 February 25, 2004.

/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. 1-8246) 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. 1-8246) 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. 1-8246) 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	Credit Agreement dated July 12, 2001 among Southwestern Energy Company, Bank One, N.A., Royal Bank of Canada, Fleet National Bank, Wells Fargo Bank Texas, N.A., Compass Bank and Hibernia National Bank, as lenders, Bank One, N.A. as administrative agent, Royal Bank of Canada, as syndication agent. (Incorporated by reference to Exhibit 4.5 to the Registrant's Annual Report filed on Form 10-K (Commission File No. 1-8246) for the year ended December 31, 2001). This credit agreement is no longer in effect.
4.6*	Credit Agreement dated January 2, 2004 among Southwestern Energy Company, Bank One, N.A., Royal Bank of Canada, Fleet National Bank, Wells Fargo Bank Texas, N.A., Compass Bank, Hibernia National Bank, Suntrust Bank, Washington Mutual Bank, FA, Arvest and Bank of Arkansas, N.A., as lenders, Bank One, N.A. as administrative agent, Royal Bank of Canada, as syndication agent.
4.7*	Credit Agreement dated January 2, 2004 between Southwestern Energy Company and Bank One, N.A.
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. 1-8246) 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. 1-8246) 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. 1-8246) 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. 1-8246) for the year ended December 31, 1998)

10.5	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. 1-8246) for the 2000 Annual Meeting of Shareholders)
10.6	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. 1-8246) for the year ended December 31, 1995)
10.7	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. 1-8246) for the year ended December 31, 1993)
10.8	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. 1-8246) for the year ended December 31, 1995)
10.9	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. 1-8246) for the year ended December 31, 1997)
10.10	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. 1-8246) for the year ended December 31, 1998)
10.11	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. 1-8246) for the year ended December 31, 2002)
10.12	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. 1-8246) for the year ended December 31, 2002)
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