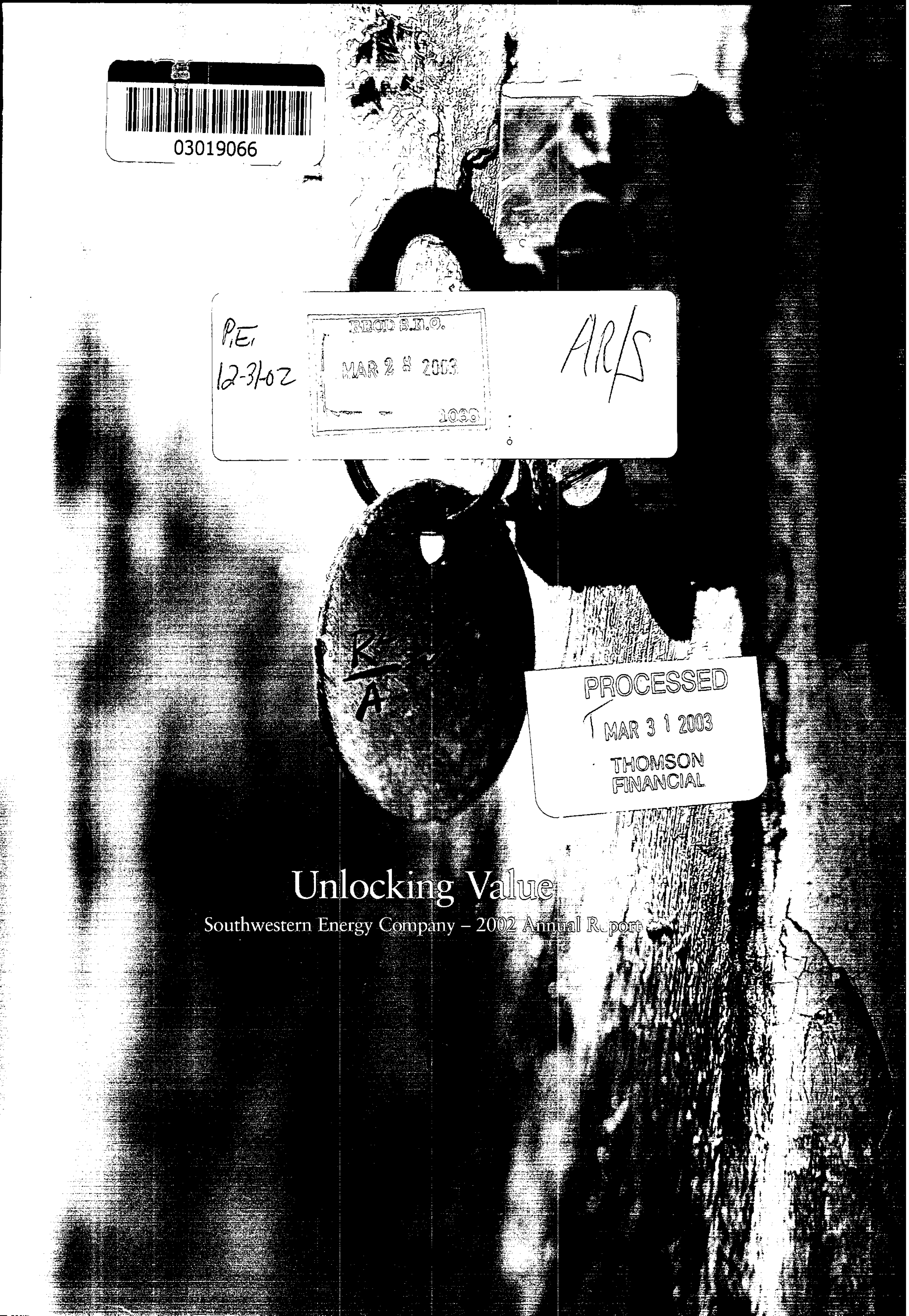


Unlocking Value

Southwestern Energy Company – 2002 Annual Report

$$\frac{R^2}{A} \rightarrow V^{+}$$

The Right People doing the Right Things, wisely investing the cash flow from the underlying Assets will create Value +.

Southwestern Energy Company is primarily focused on natural gas. Southwestern is engaged in natural gas and crude oil exploration and production activities in Arkansas, Oklahoma, Texas, New Mexico, and Louisiana. The Company's low-risk development drilling activities in the Arkoma Basin and in East Texas are complemented by moderate-risk exploration and exploitation efforts in the Permian Basin and an inventory of high-potential exploration opportunities in the onshore Gulf Coast. Southwestern also is involved in natural gas gathering, transmission, distribution, and marketing.

2002 Highlights

209% reserve replacement ratio*
$1.02 per Mcfe finding and development cost*
Record production of 40.1 Bcfe
Significant value creation at Overton Field

* Excludes reserve revisions. Including revisions, our reserve replacement ratio was 215% and our finding and development cost was $0.99 per Mcfe.

Dear Shareholders:

We are happy to record 2002 as another very positive year for Southwestern Energy Company. Although commodity prices were less robust than the prior year, we continued to deliver positive financial results with operating income of $46.5 million and earnings of $14.3 million. Our results from the drill bit continued to be impressive. We replaced 209% of our production volumes by adding an estimated 83.7 Bcfe of proved natural gas and oil reserves at an excellent finding and development cost of $1.02 per Mcfe. In addition, although we sold our western Oklahoma properties in the 4th quarter, we grew our production to 40.1 Bcfe for the year.

Operationally, the Overton Field in East Texas was the highlight for the year. We continued our drilling success at Overton with 18 more wells in 2002, bringing the total drilled since our acquisition of the field to 33 with a 100% success rate. Continued downspacing should allow us to drill approximately 100 additional wells in the area over the next two years. In the Arkoma Basin, we continued our track record of producing excellent results from this core asset. Our goal for the Arkoma is to continue our development drilling and workover programs at a level that maintains our production and reserve base. South Louisiana continues to be the main focus area of our exploration activities, however, our results there in 2002 were not as positive as in prior years. We remain excited about the exploration potential of this area and believe that our recent acquisition of the 135-square mile Duck Lake 3-D seismic data has set the stage for an active exploration program in 2003 and beyond.

As I write this letter, we have just successfully completed a follow-on offering of 8,250,000 shares of common stock in which we raised $89.8 million. The impetus for this offering (the first follow-on offering in the Company's public history) is to accelerate the infill development drilling program at Overton. The Overton project is a prime example of our focus on Unlocking Value.

$103.2	$134.6	$99.8
'00	'01	'02

EBITDA (in millions)

35.7	39.8	40.1
'00	'01	'02

Production (Bcfe)

Over the past four years we have described our business strategy simply with the formula $\frac{R^2}{A} \rightsquigarrow V^+$. We define the V^+ side of the equation by a single parameter we call PVI (discounted present value created divided by capital invested). The current discontinuity in commodity prices and service costs makes a very compelling case to harvest the Overton Field today. Assuming a $4.00 per Mcf NYMEX gas price and a total cost of $1.5 million to drill each well, our Overton project yields a PVI of $1.90 for each dollar invested.

In addition to positioning us to move forward with the Overton development which will accelerate our production and reserve growth, the equity offering significantly improves our balance sheet, provides us with financial flexibility, and increases liquidity for our shareholders. We believe the offering will be a very positive step for our Company.

We have a very exciting year ahead in 2003 as we continue our Arkoma strategy, accelerate our Overton drilling and pursue our exploration opportunities in South Louisiana. This year approximately 83% of our capital investments will be directed to drilling wells—at a time when the nation needs a secure domestic energy supply.

In conclusion, I want to thank our dedicated and creative employees for their contribution to the success of this Company and our shareholders for their support of our strategy.

Harold M. Korell
President and Chief Executive Officer

'00	'01	'02
196%	224%	209%

Reserve Replacement

'00	'01	'02
$0.99	$1.11	$1.02

Finding & Development Cost ($/Mcfe)

Financial Highlights

Operating Income $46.5 MM

78 16 6 (shown as % of 100)

EBITDA $99.8 MM

83 14 3 (shown as % of 100)

Assets $740.2 MM

71 22 7 (shown as % of 100)

Capital Investments $92.1 MM

92 7 1 (shown as % of 100)

- Exploration & Production
- Gas Distribution
- Marketing & Other

		2002	2001	2000
Revenues and Earnings	Operating revenues (in millions)	$ 261.5	$ 344.9	$ 363.9
	Operating income (in millions)	$ 46.5	$ 82.7	$ 57.8 [1]
	Net income (in millions)	$ 14.3	$ 35.3	$ 20.5 [1]
	Diluted earnings per share	$ .55	$ 1.38	$ .82 [1]
	Cash flow from operations (before working capital changes) (in millions)	$ 79.8	$ 112.7	$ 82.4 [1]
	EBITDA (in millions)	$ 99.8	$ 134.6	$ 103.2 [1]
	Capital expenditures (in millions)	$ 92.1	$ 106.1 [2]	$ 75.7
	Average diluted shares outstanding (in millions)	26.1	25.6	25.0
Exploration and Production	Total proved reserves (Bcf equivalent)	415.3	402.0	380.5
	Percent of reserves natural gas	90 %	89 %	87 %
	Percent of reserves proved, developed	77 %	80 %	82 %
	Total production (Bcf equivalent)	40.1	39.8	35.7
	Average gas price ($/Mcf)	$ 3.00	$ 3.85	$ 2.88
	Average oil price ($/barrel)	$ 21.02	$ 23.55	$ 22.99
	Finding and development cost ($/Mcfe)[3]	$ 1.02	$ 1.11	$ 0.99
	Reserve replacement ratio[3]	209 %	224 %	196 %
	Reserve life (years)	10.4	10.1	10.7
Natural Gas Distribution[4]	Total throughput (Bcf)	27.3	27.1	29.8
	Utility customers at year-end	139,543	136,242	135,534
	Heating weather - percent of normal	98 %	91 %	100 %

(1) Before unusual and extraordinary items.
(2) Includes $13.5 million funded by the owner of the minority interest in Overton partnership.
(3) Excludes reserve revisions.
(4) Gas distribution statistics exclude results from the Company's Missouri utility operations that were sold in May 2000.

Arkoma Basin

The Arkoma Basin provides a solid foundation for our E&P program and represents a significant source of our production and reserves. In 2002, we continued our track record of producing excellent results from this core asset.

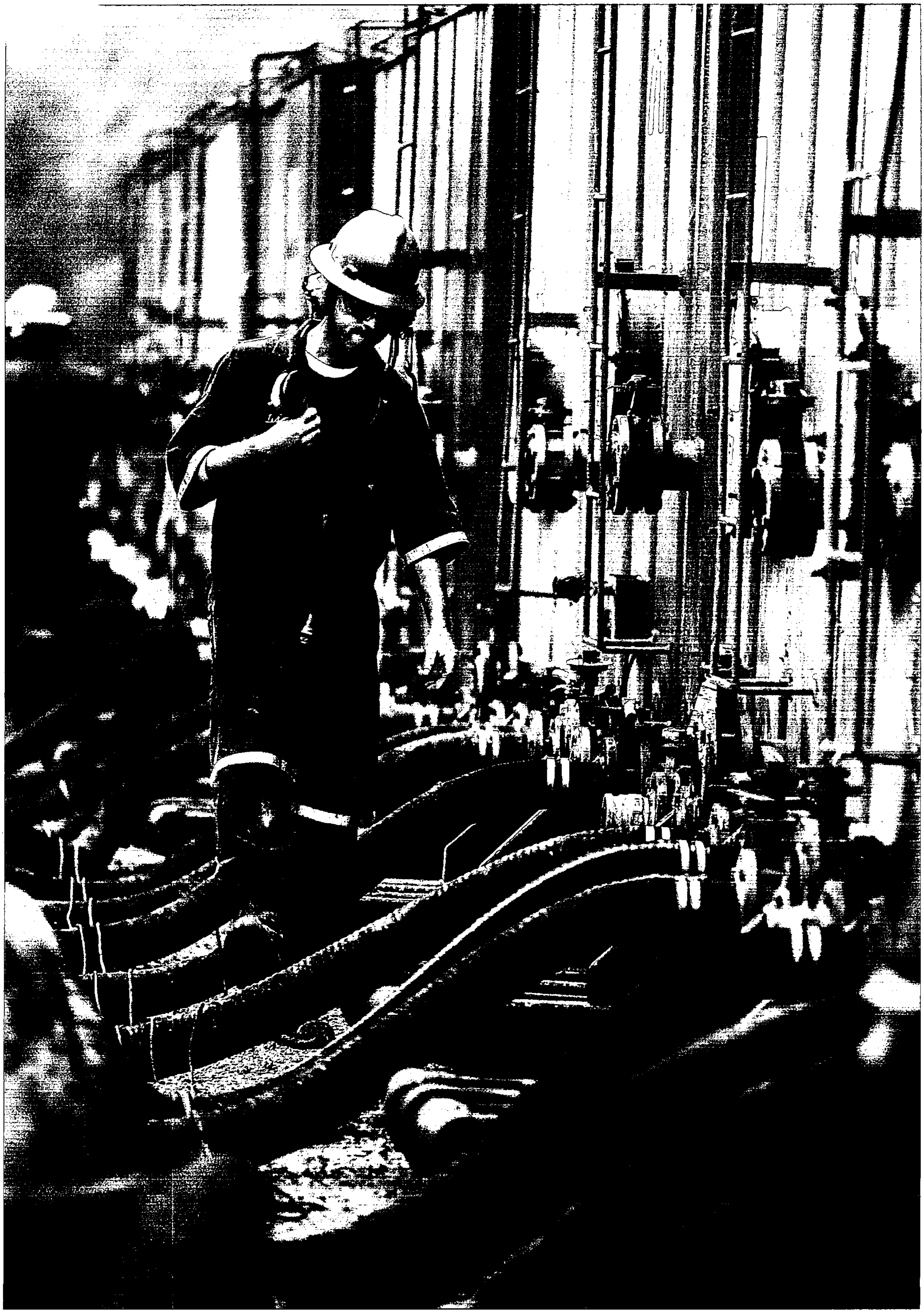
During 2002, we participated in 25 wells and 41 workovers which added 18.3 Bcf of gas reserves at a finding and development cost of $0.99 per Mcf. With average three-year finding and development costs of $1.08 per Mcf and three-year average production, or lifting, costs of $0.30 per Mcf, our cash margins in the Arkoma Basin are very favorable.

Our workover program in the Arkoma Basin includes fracture stimulations, artificial lift, recompletion and wellbore repair projects. This program has provided both reserve additions and meaningful production increases. Our workover projects in 2002 resulted in net production increases of 6.9 MMcf per day at a cost of $3.9 million.

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. We seek to delineate new geologic prospects and extend previously identified trends using our extensive database of regional structural and stratigraphic maps. In 2003, we plan to invest approximately $22.6 million in the Arkoma Basin to drill approximately 30 wells and perform approximately 60 workover projects.

The key to our success in unlocking value in the Arkoma Basin has been the ability of our people to creatively generate low-risk drilling and workover opportunities on a continuing basis. We've been doing that now for 60 years and are looking forward to unlocking even greater value in the years to come.

In the Arkoma Basin, we continue to challenge convention by finding new, low-cost reserves in existing wells, existing fields and in underexplored, technically challenging parts of the basin.



East Texas

Results at our Overton Field in Smith County, Texas continued to be exceptional in 2002. We drilled a total of 18 wells in the area during the year and all 18 were successful. Since we acquired the field in 2000, we have drilled a total of 33 wells with 100% success.

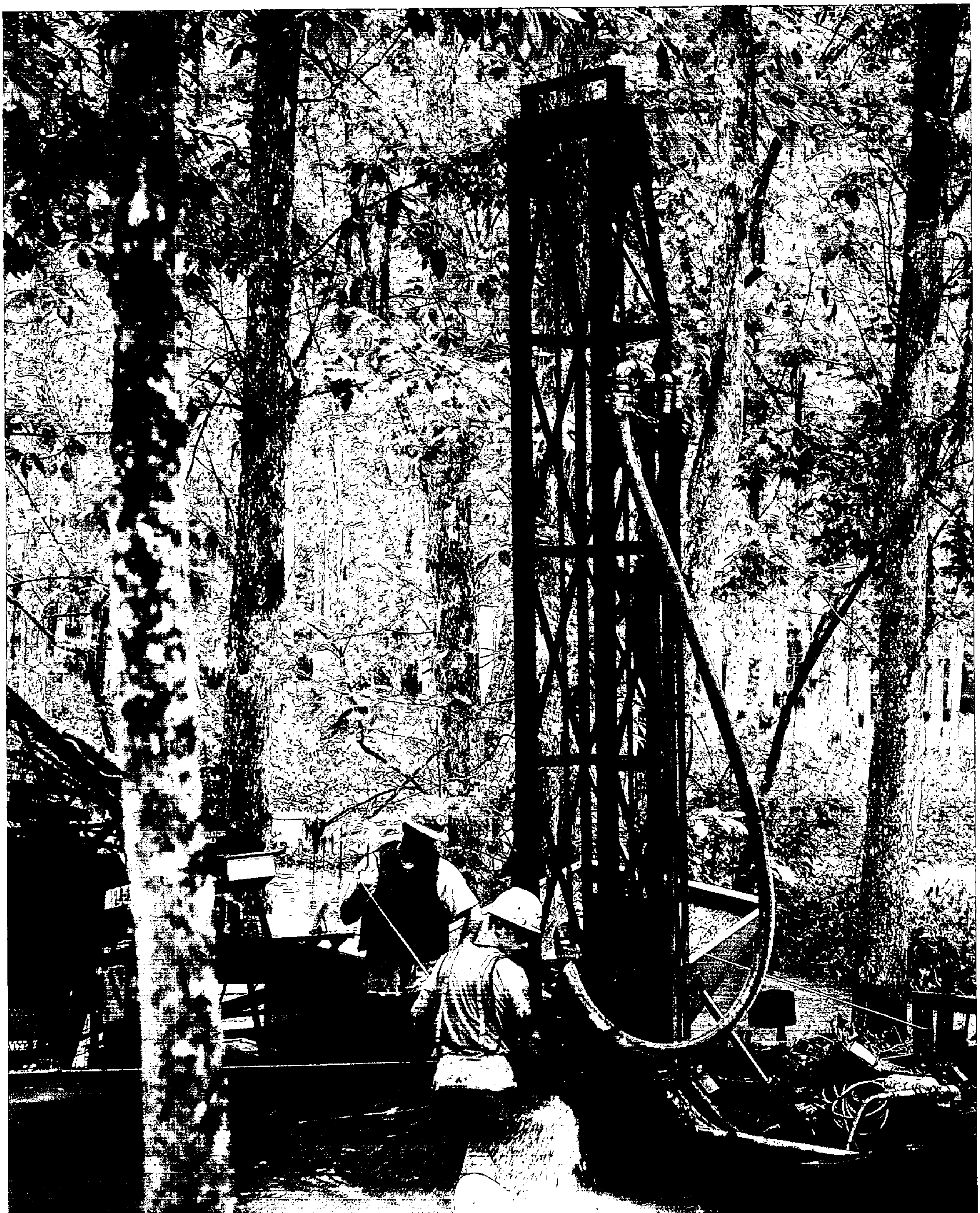
Daily gross production from Overton has increased over ten-fold from 2.0 MMcfe per day in March 2001 to 27.0 MMcfe per day at year-end 2002. As a result, our production from the area increased to 5.9 Bcfe in 2002 from 2.3 Bcfe the prior year. Additionally, our reserves at Overton nearly doubled to 111.0 Bcfe at year-end 2002, up from 57.6 Bcfe at the end of 2001.

During 2002, we continued to improve our drilling results by reducing the time to drill a well to an average of 27 days. In addition, we have realized increased production rates over previous wells by refining our well completion techniques.

The development of our Overton Field is an excellent example of our focus on adding value for each dollar we invest. We prepare economic analyses for each of our investment opportunities and rank them based upon a parameter we call PVI (the ratio of expected present value, discounted at 10%, divided by the dollars invested). We target adding $1.30 to $1.50 of pre-tax discounted present value for each dollar we invest. For example, the average economics for the wells we drilled at the Overton Field in 2002, based on current expected costs and production rates, assuming an average NYMEX price of $4.00 per Mcf of gas and $25.00 per barrel of oil, result in an estimated pre-tax PVI of $1.90 and a pre-tax rate of return of 35%.

The successful completion of our recent follow-on equity offering will allow us to accelerate the development of the Overton Field which should provide us with substantial growth in production and reserves over the next few years. Continued downspacing should allow us to drill approximately 100 wells in the area over the next two years. We intend to invest approximately $78.0 million in East Texas during 2003, which includes drilling up to 47 new wells at the Overton Field.

One of the keys to our success at our Overton Field in East Texas is our use of a completion technique called "slick water" fracturing. By pumping a combination of resin-coated sand, linear gel and water at high rates into the tight Cotton Valley Sand formation, we have increased the initial production rates and overall reserve recovery from our wells at Overton.



Gulf Coast

South Louisiana continues to be the main focus of our exploration activities. Since our first discovery in December 1999 at our Gloria Prospect, our exploration program has resulted in eight successful wells out of the last 18 drilled in South Louisiana.

We believe that significant reserves can be found in the deeper horizons of South Louisiana's sedimentary basins, and 3-D seismic is an essential exploration tool for the targeted objectives which are typically below 13,000 feet. During 2002, we completed our Duck Lake 3-D seismic survey and obtained high-quality data over 135-square miles in St. Martin and St. Mary Parishes. The new seismic data over this area has already yielded several prospects to be drilled in 2003 and numerous leads to pursue. Additionally, we completed a transaction late in 2002 with a major seismic data vendor for a license to approximately 1,000 square miles of 3-D seismic data in other prospective areas in the southern half of Louisiana. Our current 3-D database in South Louisiana includes over 2,700 square miles and has the potential to generate a significant inventory of exploration prospects.

The keys to our success in South Louisiana are our people and our 3-D seismic database. Our prospecting effort involves tying together the subsurface geology and well control information with the seismic data to unlock hidden value in this high-potential area. For 2003, we plan to invest approximately $21.7 million in the Gulf Coast region and drill up to eight exploration wells.

In 2002, we drilled over 8,000 holes, each one over 100-feet deep, in the area of our Duck Lake 3-D shoot, charged them with dynamite which was then fired to record the sound energy reflected back from deep within the subsurface over a 135-square mile area. The resulting 3-D seismic data acquired in this process has never before been seen – until now.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Natural Gas Distribution

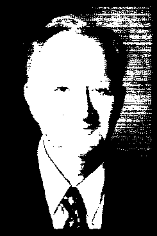
In November 2002, we set the stage for improved operating results for our utility segment by filing for an $11.0 million rate increase with the Arkansas Public Service Commission (APSC). The request for a rate increase is the first that our utility has made since 1996. In today's ever-changing economic environment, we are continuously working to control our costs. However, while we have not increased the rate we charge to deliver gas to our customers in over five years, the increased cost of doing business, the recent decline in financial markets and general inflation have required an adjustment in our rates. The APSC has ten months to review the filing and reach a decision on the amount of the increase to be approved. We expect that any increase granted would become effective in September 2003.

We continue to enjoy the benefits of having strong service territories in which we operate. Our Northwest Arkansas service territory continues to thrive and is currently listed as the 6th fastest growing community in the United States with a total population of over 300,000 in a two-county area. Multinational corporations such as Wal-Mart Stores, Inc., Tyson Foods and J.B. Hunt Transportation, six colleges and universities, more than a dozen modern medical facilities and a growing retail presence have changed the face of what was once a string of quiet agricultural communities. The impressive development of Northwest Arkansas continues to be an important key to our utility's success, as 86% of our utility customers are located in this part of the state. Our natural gas distribution business continues to be a positive contributor to our earnings and cash flow, and we are committed to continue to provide our customers with a clean and affordable energy supply for the future.

In 2002, we added over 3,300 new customers for our utility. In 2003, we will not only be focused on increasing our customer base and throughput, but also on converting customers to natural gas who are currently using alternative energy sources.

Directors

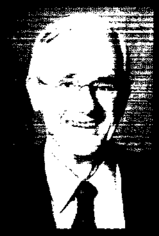

Lewis E. Epley, Jr.


John Paul Hammerschmidt


Robert L. Howard


Harold M. Korell


Kenneth R. Mourton


Charles E. Scharlau

Executive Officers

Directors

Lewis E. Epley, Jr. (5)
Attorney at Law

John Paul Hammerschmidt (11)
Retired, U.S. Congressman

Robert L. Howard (8)
Retired, Shell Oil Company

Harold M. Korell (6)
President, Chief Executive Officer and Chairman of the Board, Southwestern Energy Company

Kenneth R. Mourton (8)
Managing Partner, Ball and Mourton, Ltd., PLLC

Charles E. Scharlau (51)
Retired CEO, Southwestern Energy Company

Corporate Officers

Harold M. Korell (6)
President, Chief Executive Officer and Chairman of the Board

Greg D. Kerley (13)
Executive Vice President and Chief Financial Officer

Mark K. Boling (1)
Executive Vice President, General Counsel and Secretary

Dee W. Hency (25)
Vice President - Administration and Chief Information Officer

Timothy J. O'Donnell (12)
Vice President - Human Resources and Treasurer

Stanley T. Wilson (17)
Controller and Chief Accounting Officer

Subsidiary Operating Officers

Southwestern Energy Production Company and SEECO, Inc.

Richard F. Lane (5)
Executive Vice President

Jim R. Dewbre (5)
Vice President - Land

J. Alan Stubblefield (5)
Vice President - Production

John D. Thaeler (4)
Vice President - SEECO, Inc.

Arkansas Western Gas Company

Charles V. Stevens (31)
Senior Vice President

Ricky A. Gunter (30)
Vice President - Rates and Regulation

Bob Lamb (12)
Vice President - Community Development

Jeffrey L. Dangeau (17)
General Counsel and Secretary

Glenn M. Morgan (26)
Controller and Treasurer

Years of service with the Company are shown in parentheses.

Photo of Executive Officers as shown from left to right:
Harold M. Korell
Greg D. Kerley
Richard F. Lane
Mark K. Boling
Charles V. Stevens

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, 2002

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 13, 2003, of the Registrant's Common Stock, par value $0.10, was 25,980,378. The aggregate market value of the voting stock held by non-affiliates of the Registrant was $289,713,706 based on the New York Stock Exchange - Composite Transactions closing price on February 13, 2003, of $11.40. 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 14, 2003 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, 2002

TABLE OF CONTENTS

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. 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, along with other information about us and our operations, financial information, other documents filed with the Securities and Exchange Commission, or the SEC, and other useful information about us can found on our website at http://www.swn.com.

PART I

ITEM 1. BUSINESS

Overview

Southwestern Energy Company is an independent energy company primarily focused on the exploration for and production of natural gas. 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" operates 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 properties 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 140,000 retail customers. Arkansas Western is the largest single purchaser of SEECO's gas production.

3. *Marketing, Transportation and Other* - 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. We also hold a 25% general partnership interest in the NOARK Limited Partnership, which we refer to as NOARK, which owns the Ozark Pipeline, a 749-mile interstate pipeline with a total throughput capacity of 330 MMcf per day, along with related gathering systems. We also own an interest in approximately 150 acres of real estate, most of which is undeveloped and located in Fayetteville, Arkansas.

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 $1.30 to $1.50 of discounted pre-tax PVI for each dollar we invest. For example, the average economics for the wells we drilled at the Overton Field in 2002, based on current expected costs and production and assuming an average NYMEX price of $4.00 per Mcf of gas and $25.00 per barrel of oil, would result in an estimated discounted pre-tax PVI of $1.90 for every dollar invested. This would result in an approximate pre-tax rate of return of 35%. 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.

- *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.

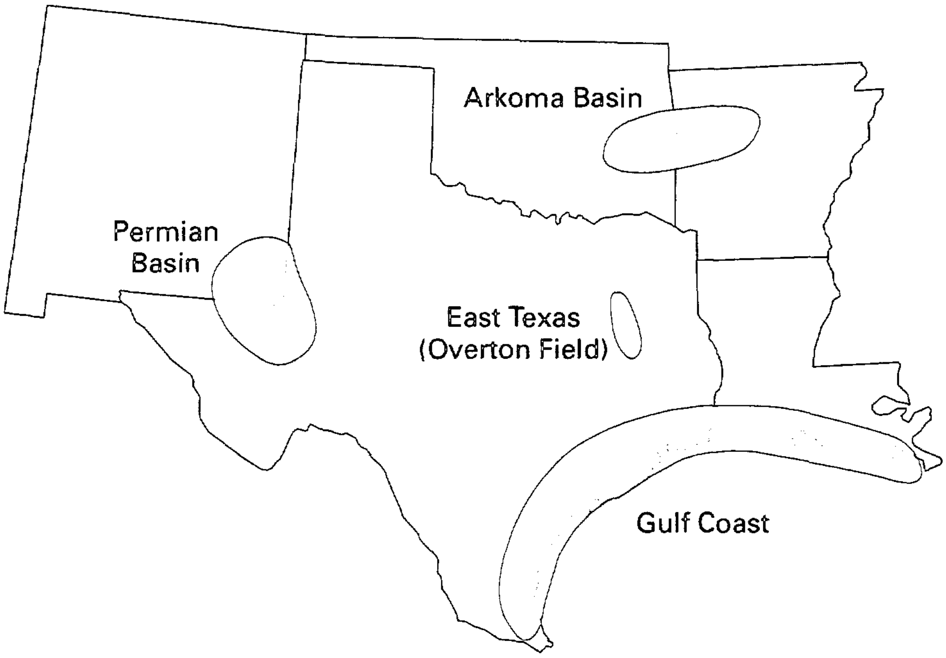
- *Pursue Strategic Acquisitions.* We selectively review opportunities to acquire producing properties and leasehold acreage, focusing in particular on the regions where we have existing operations. In addition, we seek to acquire operational control of properties that we believe have significant exploration and exploitation potential.

Recent Development

Sale of Our Mid-Continent Properties. 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. We expect this divestiture to result in a decrease in our future average production costs per unit of production. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations - Exploration and Production - Operating Costs and Expenses."

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 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 $36.0 million and EBITDA was $83.1 million in 2002. Our operating income and EBITDA declined in 2002 from $69.3 million and $115.0 million, respectively, in 2001, primarily because lower realized natural gas and oil prices decreased our revenues while our operating expenses slightly increased. We refer you to "Business-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 operating income as derived from our audited financial information.

As of December 31, 2002, our estimated proved natural gas and oil reserves were 415.3 Bcfe and had a pre-tax PV-10 value of $694.1 million. Approximately 90% of our proved reserves were natural gas and 77% were classified as proved developed. We operate approximately 74% of our reserves, based on our pre-tax PV-10 value, and our average proved reserves-to-production ratio, or average reserve life, approximated 10.4 years at year-end 2002. Revenues of our E&P subsidiaries are predominantly generated from production of natural gas. Sales of natural gas production accounted for 88% of total operating revenues for this segment in 2002, 89% in 2001, and 82% in 2000.

In 2002, we replaced 209% of our production volumes by adding an estimated 83.7 Bcfe of proved natural gas and oil reserves at a finding and development cost of $1.02 per Mcfe, excluding reserve revisions. Our finding and development cost including the effect of upward reserve revisions due to higher year-end commodity prices was $0.99 per Mcfe in 2002. For the three years ended December 31, 2002, we achieved an average reserve replacement ratio of 210% and an average finding and development cost of $1.04 per Mcfe, excluding reserve revisions. Including reserve revisions, these three-year averages were 193% and $1.13 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, greater-potential exploration opportunities in the onshore Gulf Coast region. The following table provides information as of December 31, 2002 related to proved reserves, well count, and net acreage, and 2002 annual information as to production and capital expenditures, for each of our core operating areas and overall:

	Arkoma	East Texas	Permian	Gulf Coast	Total
Estimated Proved Reserves:					
Total Reserves (Bcfe)	188.7	111.0	57.1	58.5	415.3
Percent of Total	45%	27%	14%	14%	100%
Percent Natural Gas	100%	95%	52%	86%	90%
Percent Proved Developed	84%	65%	83%	74%	77%
Production (Bcfe)	19.8	5.9	6.9(1)	7.5	40.1
Capital Expenditures (millions)	$ 18.2	$ 33.6	$ 5.4	$ 28.0	$ 85.2
Total Gross Wells	813	49	386	79	1,327
Total Net Acreage	263,112	16,117	39,425	82,770	401,424
Net Undeveloped Acreage	99,341	5,529	22,391	57,962	185,223
Pre-tax PV-10:					
Amount (millions)	$ 329.1	$ 151.9	$ 90.2	$ 122.9	$ 694.1
Percent of Total	47%	22%	13%	18%	100%
Percent Operated	79%	96%	38%	54%	74%

(1) Includes 2.0 Bcfe of production related to the Mid-Continent properties sold during 2002.

Arkoma Basin. The Arkoma Basin provides a solid foundation for our E&P program and represents a significant source of our production and reserves. At December 31, 2002, we had approximately 188.7 Bcf of natural gas reserves in the Arkoma Basin, representing approximately 45% of our total reserves. During 2002, we participated in 25 wells and 41 workovers which added 18.3 Bcf of gas reserves at a finding and development cost of $0.99 per Mcf. Our gas production in the Arkoma Basin was 19.8 Bcf during 2002, or 54.2 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 $1.08 per Mcf and three-year average production, or lifting, costs of $0.30 per Mcf (including production taxes), our cash margins in the Arkoma Basin are very attractive. Lifting costs continued to be low during 2002 at $0.36 per Mcf (including production taxes). Including the impact of commodity hedges, we realized 83% of the average price we received for natural gas from the Arkoma Basin, after direct general and administrative expenses and cash expenses.

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 2002, we completed 8 wells out of 11 drilled in the fairway and those wells added 3.9 Bcf of new natural gas reserves. An especially encouraging prospect among the fairway wells is the Grimmer #1-17 well, which is located in Johnson County, Arkansas and, as of April 2002, tested at a rate of 10.7 MMcf per day from Hale perforations at 4,100 feet. Our average working interest in the 2002 fairway wells is 67% and our average net revenue interest is 58%. We intend to drill up to 15 wells in the fairway portion of the Arkoma Basin in 2003.

In recent years, we have extended our development program into the Oklahoma portion of the Arkoma Basin, and have also tested new exploration plays to continue its growth. In 2002, we continued the development of our Ranger Anticline prospect area, located at the southern edge of the Arkansas portion of the basin. An example of our continued successful development of this complex overthrust play is the Brasher #1-11 well that was drilled and put into production in August 2002 at a rate of 12.0 MMcf per day from Lower Borum sands at approximately 5,500 feet and 6,750 feet. We have begun testing new exploration prospect areas on the southern edge of the Arkoma Basin similar to our Ranger Anticline play.

Additionally in 2002, we accelerated our extensive workover program in the Arkoma Basin which includes fracture stimulations, artificial lift, recompletion and wellbore repair projects, and this acceleration has provided meaningful production increases. We performed 41 of these workover projects in 2002, resulting in net production increases totaling 6.9 MMcf per day at a total net cost of $3.9 million. One workover project, the Currier #1-35 well in Franklin County, Arkansas, was recompleted to the Sells zone and stimulated in the Casey sand. This work increased gross production from the well by 850 Mcf per day and resulted in a net reserve addition of 1.1 Bcf.

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 2003, we plan to invest approximately $22.6 million in the Arkoma Basin to drill approximately 30 wells and perform approximately 60 workover projects. 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 for 2003.

East Texas. The Overton Field in Smith County, Texas provides us with 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 16,500 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 expect to receive regulatory approval to allow downspacing of our properties in the Overton Field to 80-acre spacing, which will provide us with an extensive inventory of additional drilling locations. Our average working interest in the Overton Field is 97% and our average net revenue interest is 79%.

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. The farm-in agreement requires us to drill a minimum of one well per 120 days on this acreage in 2003. 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 2002 and 2001 revenues, less operating costs and expenses, was $1.5 million and $0.9 million, respectively.

We continue to pursue potential acquisitions in the Overton Field area and during 2002 we acquired 3,300 net acres of land offsetting recent Travis Peak and Cotton Valley development in Anderson County, Texas. While undeveloped at this time, we see the potential to apply technologies we refined in the Overton Field to this acreage block, which is located approximately 55 miles southwest of the Overton Field.

In 2002, we drilled a total of 15 wells at the Overton Field and three wells at South Overton. All 18 wells were successful. To date, we have drilled a total of 33 wells in the area with a 100% success rate. Daily gross production at the Overton Field has increased from 2.0 MMcfe in March 2001 to approximately 27.0 MMcfe at year-end 2002 resulting in net production of 5.9 Bcfe during 2002. Our average production costs (including production taxes) decreased to $0.40 per Mcfe in 2002 from $0.70 per Mcfe in 2001, and that unit rate could decline further as production from the field increases.

Our proved reserves at the Overton Field increased to 111.0 Bcfe at year-end 2002, or 27% of our total reserves. We invested approximately $33.6 million at the Overton Field during 2002 which resulted in proved reserve additions of 56.4 Bcfe with a finding and development cost of $0.60 per Mcfe compared to a finding and development cost of $0.82 per Mcfe at the Overton Field in 2001.

Continued downspacing should allow us to drill an additional 100 wells in the area over the next two years. This should achieve 80-acre spacing in the majority of the higher potential areas. Our results at the Overton Field over the past two years have been significant and we believe that the acceleration of the field's development will provide substantial growth in production and reserves over the next few years. We intend to invest approximately $78.0 million in East Texas during 2003, which includes drilling up to 47 new wells using four rigs at the Overton Field. 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 2003.

Permian Basin. At December 31, 2002, our proved reserves in the Permian Basin were 57.1 Bcfe, or 14% of our total reserves. Our production in the basin during 2002 was 4.9 Bcfe, or 13.4 MMcfe per day, and our production costs (including production taxes) averaged $1.13 per Mcfe. During 2002, our capital expenditures totaled $5.0 million, resulting in reserve additions of 1.4 Bcfe. Excluding reserve revisions, our three-year average finding and development cost in the basin was $2.23 per Mcfe and three-year average reserve replacement ratio was 85% for the period ended December 31, 2002.

While our overall results in the basin were disappointing in 2002, we have recently experienced some encouraging results from drilling horizontal wells targeting the Cherry Canyon sand formation. The Peregrine #1 well located in Eddy County, New Mexico, was drilled and completed in 2002 in the Cherry Canyon horizon at 4,850 feet, with a 1,390-foot horizontal lateral. We estimate that the well exposed 720 feet of well-developed pay. We operate this well with a 100% working interest. This well is currently producing approximately 90 barrels of oil per day and we expect to drill up to three more horizontal wells in this area in 2003.

We de-emphasized our drilling activities in the Permian Basin in 2002 and will continue to do so in 2003. In 2003, we plan to invest approximately $4.8 million in the Permian Basin, to drill up to nine wells. 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 2003.

Gulf Coast. Our Gulf Coast operations are located in the onshore areas of Texas and Louisiana. Our proved reserves in these areas totaled 58.5 Bcfe at December 31, 2002, or 14% of our total revenues. Approximately 29.8 Bcfe of our proved reserves in the Gulf Coast was located in Louisiana. Average net daily production in the Gulf Coast area was 20.5 MMcfe and production costs (including production taxes) averaged $1.07 per Mcfe during 2002. We invested $28.0 million in the area in 2002 and added 7.6 Bcfe of proved reserves. Of the $28.0 million in capital investments, approximately $5.8 million was invested in leasehold and seismic for future prospect development. Excluding reserve revisions, our three-year average finding and development cost in the Gulf Coast region was $1.83 per Mcfe and three-year reserve replacement ratio was 246% for the period ending December 31, 2002. Including revisions, these three-year averages were $2.13 per Mcfe and 212%.

South Louisiana continues to be the main focus area of our exploration activities in the Gulf Coast. Since our first discovery in December 1999, the efforts of our exploration program have resulted in eight successful wells out of the last 18 drilled in South Louisiana. In 2002, we participated in eight wells, of which two were successful. During 2002, we were also active in acquiring seismic data to facilitate future exploration in the area. We completed our 135-square mile Duck Lake 3-D seismic project located in St. Martin and St. Mary Parishes and are currently interpreting that data for prospects to be drilled later in 2003 and beyond. We are the operator of this project, and hold a 50% working interest. Additionally, we completed a transaction late in 2002 with a major seismic data vendor for a license to approximately 1,033 square miles of 3-D seismic data in other prospective areas in the southern half of Louisiana. Our current 3-D database in South Louisiana now includes over 2,700 square miles, has the potential to generate a significant inventory of exploration prospects and leads. For 2003, we plan to invest approximately $21.7 million in the Gulf Coast region and drill up to eight exploration wells. 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 2003.

Acquisitions

In 2002, we purchased 6.6 Bcfe of proved reserves for direct costs of $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 2001, we purchased proved reserves of 4.5 Bcfe for direct costs of $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 direct costs of $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 direct costs of $9.4 million. We did not make any producing property acquisitions in 1998.

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 $85.2 million in our E&P program and participated in drilling 65 wells during 2002. Of these drilled wells, 45 were successful, 16 were dry and 4 were still in progress at year-end. Our investments were balanced between our core areas of operations, with approximately $18.2 million invested in the Arkoma Basin, $33.6 million in East Texas, $5.4 million in the Permian Basin and Mid-Continent areas, and $28.0 million in the Gulf Coast. Of the $85.2 million invested, approximately $15.5 million was invested in exploratory drilling, $46.1 million in development drilling and workovers, $9.1 million for land and leasehold acquisition and seismic expenditures, $3.1 million for producing property acquisitions, and $11.4 million in capitalized interest and expenses and other technology-related expenditures.

In 2003, our planned E&P capital budget is $137.1 million, with approximately 83% allocated to drilling. The majority of our investments in 2003 will be directed to the lower-risk part of our E&P portfolio, primarily due to our planned acceleration of the development of the Overton Field in East Texas. In 2003, approximately 73% of our capital will be allocated to lower-risk development drilling activities in the Arkoma Basin ($22.6 million) and East Texas ($78.0 million). The remainder of our capital will be allocated to medium-risk exploration and exploitation in the Permian Basin ($4.8 million), higher risk exploration in South Louisiana ($21.7 million) and capital investments in other frontier areas ($10.0 million). Of the $137.1 million capital budget, approximately $16.1 million will be invested in exploratory drilling, $97.2 million in development drilling and workovers, $12.0 million for land and leasehold acquisition and seismic expenditures, and $11.8 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 2003.

Sales and Major Customers

Our daily natural gas equivalent production averaged 109.8 MMcfe in 2002, compared to 109.0 MMcfe in 2001 and 97.7 MMcfe in 2000. Our natural gas production was 36.0 Bcf in 2002, compared to 35.5 Bcf in 2001 and 31.6 Bcf in 2000. We also produced 682,000 barrels of oil in 2002, compared to 719,000 barrels of oil in 2001 and 676,000 barrels in 2000. We are targeting production in 2003 to be approximately 42 Bcfe to 44 Bcfe.

We realized an average wellhead price of $3.00 per Mcf for our natural gas production in 2002, compared to $3.85 per Mcf in 2001 and $2.88 per Mcf in 2000, including the effect of hedges. Our hedging activities lowered the average gas price $0.11 per Mcf in 2002, $0.31 per Mcf in 2001, and $1.04 per Mcf in 2000. Our average oil price realized was $21.02 per barrel in 2002, compared to $23.55 per barrel in 2001 and $22.99 per barrel in 2000, including the effect of hedges. Our hedging activities lowered the average oil price $2.92 in 2002, $0.03 per barrel in 2001 and $6.39 per barrel in 2000.

Our gas sales to unaffiliated purchasers were 30.6 Bcf in 2002, compared to 30.4 Bcf in 2001 and 23.8 Bcf in 2000. 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 85% of total E&P revenues in 2002, 83% in 2001 and 76% in 2000.

Our utility subsidiary, Arkansas Western is the largest single customer for sales of our gas production and the only customer that accounted for more than 10% of our natural gas and oil production revenue in 2002. 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 15% of total E&P revenues in 2002, 17% in 2001 and 24% in 2000. SEECO's sales to Arkansas Western were 5.4 Bcf in 2002, compared to 5.1 Bcf in 2001 and 7.8 Bcf in 2000. The increase in sales in 2002 was primarily caused by increased supply requirements due to colder weather when compared to 2001. Weather in 2002, as measured in degree days, was 8% colder than in 2001 and 2% warmer than normal. The decrease in sales in 2001 was primarily due to warmer weather and the sale of the utility's Missouri gas distribution properties in May 2000. Weather in 2001, as measured in degree days, was 9% warmer than both normal and the prior year for Arkansas Western's service territory. SEECO's gas production provided approximately 37% of the utility's requirements in 2002, 33% in 2001 and 42% in 2000. 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, 2002, we had hedges in place on 42.6 Bcf of future gas production and 240,000 barrels of future oil production. Subsequent to December 31, 2002 and prior to February 14, 2003, we hedged 3.0 Bcf of 2003 gas production under costless collars with floor prices of $4.00 per Mcf and ceiling prices ranging from $5.85 to $6.20 per Mcf, and 100,000 barrels of future oil production at $29.40 per barrel. We currently have hedges in place on approximately 75% of our targeted 2003 gas production and approximately 65% of our 2003 targeted oil production. We refer you to "Quantitative and Qualitative Disclosures About Market Risks," for further information regarding our hedge position at December 31, 2002.

Disregarding the impact of hedges, we expect the average price received for our gas production to be approximately $0.10 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. While sales by producers of natural gas can currently be made at uncontrolled market prices, 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 140,000 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. 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 large corporations such as Tyson Foods and J.B. Hunt Transportation have also contributed to this area's development. Approximately 86% of Arkansas Western's customers are located in this part of the state and, in recent years, Arkansas Western has experienced customer growth of approximately 2% to 3% annually.

Operating income for our natural gas distribution business was $7.6 million in 2002, compared to $10.3 million in 2001 and $12.6 million in 2000 (excluding the Missouri utility properties). EBITDA generated by our utility segment was $14.0 million in 2002, compared to $17.1 million in 2001 and $20.7 million in 2000 (excluding the Missouri utility properties). We refer you to "Business-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 operating income as derived from our audited financial information. Our operating income and EBITDA decreased primarily due to increased operating costs and expenses and reduced usage per customer brought about by high gas prices. We filed for an $11.0 million annual rate increase with the Arkansas Public Service Commission, or the APSC, in November 2002. The requested increase is the first Arkansas Western has made since 1996. The APSC has ten months to review the filing and reach a decision on the amount of the increase, if any, to be approved, therefore, we expect that any increase granted would be effective during the fall of 2003.

In June 2000, we announced we were pursuing the sale of our utility operations in Arkansas to fund a $109.3 million judgment against us, which we refer to as the Hales judgment. Although we received several serious expressions of interest from bona fide parties, we did not receive an offer that was acceptable to us. We are no longer pursuing a sale of the utility system and intend to operate the Arkansas utility properties as a continuing part of our business.

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 2002, SEECO successfully bid on gas supply packages representing approximately two-thirds of the requirements for Arkansas Western for 2003.

Arkansas Western also purchases gas for its system supply 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 5% 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 purchased gas adjustment clauses whereby the actual cost of purchased gas above or below the level included in the base 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 123,000 residential, 16,400 commercial, and 200 industrial customers, while also providing gas transportation services to approximately 70 end-use and off-system customers. Total gas throughput in 2002 was 27.3 Bcf, compared to 27.1 Bcf in 2001 and 33.4 Bcf in 2000. The higher volumes in 2002 were due to weather that was 8% colder than in 2001 and an increase in volumes delivered to the utility's end-use transportation customers. The decrease in 2001 resulted from the loss of throughput associated with the sale of the utility's Missouri assets in May 2000 and warmer weather. Off-system transportation volumes were 2.2 Bcf in 2002 and 3.1 Bcf in both 2001 and 2000.

Residential and Commercial. Approximately 87% of the utility's revenues in 2002 were from residential and commercial markets. Residential and commercial customers combined accounted for 56% of total gas throughput for the gas distribution segment in 2002, compared to 54% in 2001 and 55% in 2000. Gas volumes sold to residential customers were 9.0 Bcf in 2002, compared to 8.4 Bcf in 2001 and 10.9 Bcf in 2000. Gas sold to commercial customers totaled 6.2 Bcf in 2002, 6.1 Bcf in 2001 and 7.6 Bcf in 2000. The increases in gas volumes sold in 2002 were due to weather that was 8% colder than in 2001. The decreases in gas volumes sold in 2001 were due to the sale of the Missouri utility properties and warmer weather. Weather during 2001 was 9% warmer than both normal and the prior year.

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 recently as tariffs implemented in Arkansas 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 9.9 Bcf in 2002, 9.5 Bcf in 2001 and 11.8 Bcf in 2000. The decrease in deliveries in 2001 was primarily due to the sale of the utility's Missouri properties. 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 73 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 that we encourage. We experience increasing competition from alternative fuels such as electricity, fuel oil, and propane. Arkansas Western has historically maintained a substantial price advantage over these fuels for most applications, enabling us to achieve excellent market penetration levels. However, the high gas prices experienced in the 2000-2001 heating season temporarily eroded the price advantage in some markets. Arkansas Western has made progress in regaining price advantage in its markets as gas prices have declined from the levels experienced during the winter of 2000-2001. Arkansas Western also has the ability through its approved tariffs to lower its rates to large customers to be competitive with available alternative fuels or if the threat of bypass exists. This tariff is likely to be eliminated in the pending rate case and replaced with an alternative mechanism that will require APSC approval for rate discounts.

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 aggressively 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. Furthermore, legislation has been recently introduced seeking to repeal the deregulation of the retail sale of electricity. It is unknown whether additional legislation will be adopted or, if it is adopted, what its final form will be. If electric deregulation occurs in Arkansas, legislative or regulatory precedents may be set that would also affect natural gas utilities in the future. These effects may include further unbundling of services 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 is the first Arkansas Western has made since 1996. The APSC has ten months to review the filing and reach a decision. As a result, Arkansas Western expects that any increase granted would be effective in the fall of 2003. Arkansas Western's most recent 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.

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, 2001, Arkansas Western had over-recovered purchased gas costs of $8.2 million. At December 31, 2002, Arkansas Western had approximately $5.7 million of over-recovered purchased gas costs.

In May 1999, the staff of the APSC initiated a proceeding in which it sought an annual reduction of approximately $2.3 million in the rates Arkansas Western charges its customers in Northwest Arkansas. Staff's position was based on various adjustments to the utility's rate base, operating expenses, capital structure and rate of return. A large portion of the proposed reduction was based on a downward adjustment to the utility's current return on equity authorized by the APSC in 1996. During the third quarter of 1999, Arkansas Western reached agreement with the staff and the APSC to resolve this issue and to close several other open dockets. In the settlement agreement, Arkansas Western agreed to reduce its rates collected from customers on a prospective basis in the amount of $1.4 million annually, effective December 1, 1999.

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% to 3% 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

Operating income from the marketing, transportation and other segment, which includes income from real property held by our subsidiary, A.W. Realty Company, was $2.9 million in 2002, compared to $3.0 million in 2001 and $2.5 million in 2000. EBITDA for this segment was $2.8 million in 2002, compared with $2.4 million in 2001 and $3.0 million in 2000. We refer you to "Business-Other Items-Reconciliation of Non-GAAP Measures" for a table that reconciles EBITDA with our operating income as derived from our audited financial information.

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 $2.7 million on revenues of $131.1 million in 2002, compared to $2.7 million on revenues of $190.3 million in 2001, and $2.5 million on revenues of $207.7 million in 2000. We marketed 45.5 Bcf of natural gas in 2002, compared to 49.6 Bcf in 2001 and 59.6 Bcf in 2000. 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 67% in 2002, 66% in 2001 and 33% in 2000.

Transportation

In January 1998, we entered into an agreement with Enogex Inc., a subsidiary of OGE Energy Corp. ("Enogex"), 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 749 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 168.1 MMcf per day in 2002, compared to 134.1 MMcf per day in 2001 and 188.2 MMcf per day in 2000.

At December 31, 2002, Arkansas Western had transportation contracts with Ozark Pipeline for 66.9 MMcf per day of firm capacity. These contracts expire in 2003 and are renewable annually thereafter until terminated with 180 days' notice. These contracts are currently being renegotiated. The merged pipeline system now has greater access to major gas producing fields in Oklahoma. We expect that the pipeline's additional 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 were losses of $0.3 million in 2002, $1.5 million in 2001 and $1.8 million in 2000. The improvements in operating results since 2000 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 150 acres of real estate, most of which is undeveloped. A.W. Realty's real estate development activities are concentrated on a 130-acre tract of land located near 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.

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 APSC had established a maximum transportation rate of approximately $0.285 per dekatherm. 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 operating 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 operating income, as derived from our audited financial information for the years-ended December 31, 2002, 2001 and 2000:

	E&P	Natural Gas Distribution	Marketing, Transportation and Other	Total
2002				
Operating income	$ 36,048	$ 7,563	$ 2,894	$ 46,505
Depreciation, depletion and amortization	48,570	6,581	201	55,352
Other income (expense)	(104)	(138)	(324)	(566)
Minority interest	(1,454)	—	—	(1,454)
EBITDA	$ 83,060	$ 14,006	$ 2,771	$ 99,837
2001				
Operating income	$ 69,340	$ 10,346	$ 2,983	$ 82,669
Depreciation, depletion and amortization	46,446	6,200	995	53,641
Other income (expense)	180	600	(1,579)	(799)
Minority interest	(930)	—	—	(930)
EBITDA	$ 115,036	$ 17,146	$ 2,399	$ 134,581
2000				
Operating income(1)	$ 40,704	$ 14,655	$ 2,460	$ 57,819
Depreciation, depletion and amortization	39,079	6,691	852	46,622
Other income (expense)	(311)	(609)	(292)	(1,212)
Minority interest	—	—	—	—
EBITDA(1)	$ 79,472	$ 20,737	$ 3,020	$ 103,229

(1) Amounts exclude unusual items of $109.3 million for the Hales judgment and $2.0 million for other litigation.

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, 2002, we had 522 total employees, including 346 employed by our natural gas utility, of which 30 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.

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.

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.

The prices for natural gas and oil could be significantly affected by the prospect and outcome of war in Iraq, for example.

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, profitability and liquidity 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%, 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. 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.

Repercussions from any terrorist act or from armed hostilities in the United States or abroad could harm our revenues, business operations, profitability or growth.

The terrorist attacks that occurred on September 11, 2001 caused significant instability in the world's markets. There can be no assurance that the armed hostilities will not escalate or that these terrorist attacks, or the United States' responses to them, will not lead to further acts of terrorism and civil disturbances in the United States or elsewhere, which may further contribute to the economic instability in the United States where we operate. Any armed conflict, civil unrest or additional terrorist activities, and the attendant political instability and societal disruption, could reduce demand for our products or disrupt our ability to conduct our exploration, production, development and marketing activities, which could harm our business.

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, 2002, approximately 23% 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 and production, marketing and transportation 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 laws and regulations, including environmental, health and safety regulation. The natural gas and oil regulatory environment could change in ways that might substantially increase these costs. Regulated matters include permits for exploration, development and production operations, such as permits for discharges of wastewaters and other substances generated in connection with drilling operations, bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning operations, the spacing of wells and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. In addition, at the U.S. federal level, the FERC regulates interstate transportation of natural gas under the NGA. 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, we are subject to various federal, state and local regulations and laws relating to the discharge of substances into, and protection of, the environment. These laws and 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 or laws 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 are required to reflect abandonment costs as a liability on their balance sheets. We may incur significant abandonment costs in the future which could adversely affect our financial results.

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

Drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such 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. We rely to a significant extent on seismic data and other advanced technologies in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that 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.

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.

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 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 facility 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;
- paying dividends on stock, 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, 2002, we had long-term indebtedness of $342.4 million, excluding $42.6 million relating to our several guarantee of NOARK's debt obligation. Indebtedness under our revolving credit facility was $117.4 million of our total long-term indebtedness.

Our hedging activities may prevent us from benefiting from price increases, may reduce our revenues 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 75% of our targeted 2003 natural gas production and approximately 65% of our targeted 2003 oil production. Our hedging activities reduced revenues by $6.1 million in 2002, $10.3 million in 2001 and $39.3 million in 2000. 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 reflected in our financial statements. We refer you to "Quantitative and Qualitative Disclosure about Market Risks."

We could be harmed if the capital markets do not recover or continue to materially decline, or if interest rates substantially rise.

If the capital markets do not recover or continue to materially decline, our earnings would decrease as a result of pension expenses that we would incur. In addition, we might not be able to finance our operations on terms we consider acceptable and our net cash flows could decrease due to higher interest rates.

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.

"Bcf" One billion cubic feet of gas.

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

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

"Bopd" Barrels of oil produced per day.

"Btu" 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 heated 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 and non-cash ceiling test write-downs of oil and gas properties. We refer you to "Business-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 operating 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" Reserves that are expected to be recovered from new wells on developed acreage where the subject reserves cannot be recovered without drilling additional wells.

"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."

"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 a gas or oil reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission.

"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-Natural Gas Distribution."

	Total
Gathering	389
Transmission	986
Distribution	3,823
	5,198

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-Exploration and Production."

Leasehold acreage as of December 31, 2002:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Arkoma	156,955	99,341	228,113	163,771
East Texas	9,711	5,529	12,216	10,588
Permian Basin	46,283	22,391	73,390	17,034
Gulf Coast	124,465	57,962	74,963	24,808
	337,414	185,223	388,682	216,201

Producing wells as of December 31, 2002:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkoma	813	410.9	—	—	813	410.9
East Texas	49	46.1	—	—	49	46.1
Permian Basin	124	20.5	262	122.6	386	143.1
Gulf Coast	52	23.7	27	10.2	79	33.9
	1,038	501.2	289	132.8	1,327	634.0

Wells drilled during the year:

Exploratory

	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
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
2000	13.0	4.0	12.0	4.8	25.0	8.8

Development

	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
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
2000	65.0	21.9	14.0	6.3	79.0	28.2

Wells in progress as of December 31, 2002:

	Gross	Net
Exploratory	1.0	0.3
Development	3.0	2.8
Total	4.0	3.1

During 2002, 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, 2002, 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	58	6
Greg D. Kerley	Executive Vice President and Chief Financial Officer	47	13
Richard F. Lane	Executive Vice President, Southwestern Energy Production Company and SEECO, Inc.	45	4
Mark K. Boling	Executive Vice President, General Counsel and Secretary	45	1
Charles V. Stevens	Senior Vice President, Arkansas Western Gas Company	53	14

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. Stevens has served us in his present position since December 1997. Previously, he served as Vice President of Arkansas Western Gas Company from 1988 to 1997.

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, 2002, we had 2,079 shareholders of record. The following prices represent the range of high and low intra-day market prices of our common stock on the New York Stock Exchange for the periods indicated.

	Range of Market Prices			
Quarter Ended	2002		2001	
March 31	$ 12.80	$ 9.60	$ 11.20	$ 8.76
June 30	$ 15.25	$ 12.40	$ 16.35	$ 8.77
September 30	$ 15.22	$ 9.51	$ 13.50	$ 10.45
December 31	$ 12.44	$ 10.27	$ 13.05	$ 9.50

We have indefinitely suspended payment of quarterly dividends on its common stock. Additionally, at the present time, the payment of dividends is prohibited by our current revolving credit facility.

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, 2002. 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."

	2002	2001	2000	1999	1998	1997
	(in thousands except share, per share, shareholder data and percentages)					
Financial Review						
Operating revenues						
Exploration and production	$ 122,207	$ 153,937	$ 110,920	$ 75,039	$ 86,232	$ 100,129
Gas distribution	115,850	147,282	151,234	132,420	134,711	154,155
Gas marketing and other	131,514	190,773	208,196	137,942	97,795	83,511
Intersegment revenues	(108,069)	(147,065)	(106,467)	(65,005)	(52,433)	(61,606)
	261,502	344,927	363,883	280,396	266,305	276,189
Operating costs and expenses						
Gas purchases - utility	48,388	68,161	58,669	45,370	39,863	46,806
Gas purchases - marketing	37,927	68,010	133,221	92,851	73,235	63,054
Operating and general	64,600	64,108	59,790	57,957	61,915	59,167
Unusual items	—	—	111,288	—	—	—
Depreciation, depletion and amortization	53,992	52,899	45,869	41,603	46,917	48,208
Write-down of natural gas and oil properties	—	—	—	—	66,383	—
Taxes, other than income taxes	10,090	9,080	8,515	6,557	6,943	7,018
	214,997	262,258	417,352	244,338	295,256	224,253
Operating income (loss)	46,505	82,669	(53,469)	36,058	(28,951)	51,936
Interest expense, net	(21,466)	(23,699)	(24,689)	(17,351)	(17,186)	(16,414)
Other income (expense)	(566)	(799)	1,997	(2,331)	(3,956)	(5,017)
Minority interest in partnership	(1,454)	(930)	—	—	—	—
Income (loss) before income taxes	23,019	57,241	(76,161)	16,376	(50,093)	30,505
Income taxes						
Current	—	—	—	537	(6,029)	(732)
Deferred	8,708	21,917	(29,474)	5,912	(13,467)	12,522
	8,708	21,917	(29,474)	6,449	(19,496)	11,790
Net income (loss)	$ 14,311	$ 35,324	$ (46,687)	$ 9,927	$ (30,597)	$ 18,715
Cash flow from operations, before working capital changes	$ 79,775	$ 112,697	$ (28,917)[1]	$ 60,818	$ 73,673	$ 85,031
Cash flow from operations, net of working capital changes	$ 77,574	$ 144,583	$ (53,203)[1]	$ 58,131	$ 93,708	$ 79,483
Return on equity	8.1%	19.3%	n/a	5.2%	n/a	8.5%
Common Stock Statistics						
Earnings (loss) per share:						
Basic	$ .57	$ 1.40	$ (1.86)	$ .40	$ (1.23)	$ .76
Diluted	$ .55	$ 1.38	$ (1.86)	$ .40	$ (1.23)	$ .76
Cash dividends declared and paid per share	$ —	$ —	$ .12	$ .24	$ .24	$ .24
Diluted book value per share	$ 6.81	$ 7.15	$ 5.64	$ 7.63	$ 7.47	$ 8.94
Market price at year-end	$ 11.45	$ 10.40	$ 10.38	$ 6.56	$ 7.50	$ 12.88
Number of shareholders of record at year-end	2,079	2,124	2,192	2,268	2,333	2,379
Average diluted shares outstanding	26,052,238	25,601,110	25,043,586	24,947,021	24,882,170	24,777,906

(1) Cash flow from operations before working capital changes for 2000 would have been $82.4 million excluding the effects of unusual and extraordinary items. Cash flow from operations, net of working capital changes, for 2000 would have been $58.1 million excluding the effects of unusual and extraordinary items.

	2002	2001	2000	1999	1998	1997
Capitalization (in thousands)						
Total debt, including current portion	$ 342,400	$ 350,000	$ 396,000	$ 302,200	$ 283,436	$ 299,543
Common shareholders' equity[1]	177,488	183,086	141,291	190,356	185,856	221,565
Total capitalization	$ 519,888	$ 533,086	$ 537,291	$ 492,556	$ 469,292	$ 521,108
Total assets	$ 740,162	$ 743,123	$ 705,378	$ 671,446	$ 647,620	$ 710,866
Capitalization ratios:						
Debt	65.9%	65.7%	73.7%	61.4%	60.3%	57.2%
Equity	34.1%	34.3%	26.3%	38.6%	39.7%	42.8%
Capital Expenditures (in millions)						
Exploration and production	$ 85.2	$ 99.0	$ 69.2	$ 59.0	$ 52.4	$ 73.5
Gas distribution	6.1	5.3	6.0	7.1	10.1	12.6
Other	.8	1.8	.5	.9	1.9	2.7
	$ 92.1	$ 106.1	$ 75.7	$ 67.0	$ 64.4	$ 88.8
Exploration and Production						
Natural gas:						
Production, Bcf	36.0	35.5	31.6	29.4	32.7	33.4
Average price per Mcf	$ 3.00	$ 3.85	$ 2.88	$ 2.21	$ 2.34	$ 2.57
Oil:						
Production, MBbls	682	719	676	578	703	749
Average price per barrel	$ 21.02	$ 23.55	$ 22.99	$ 17.11	$ 13.60	$ 19.02
Total gas and oil production, Bcfe	40.1	39.8	35.7	32.9	36.9	37.9
Lease operating expenses per Mcfe	$ .45	$ .45	$ .40	$ .35	$ .34	$ .36
Taxes other than income taxes per Mcfe	$ .19	$ .17	$ .16	$ .09	$ .09	$ .09
Proved reserves at year-end:						
Natural gas, Bcf	374.6	355.8	331.8	307.5	303.7	291.4
Oil, MBbls	6,784	7,704	8,130	7,859	6,850	7,852
Total reserves, Bcfe	415.3	402.0	380.6	354.7	344.8	338.5
Gas Distribution[2]						
Sales and transportation volumes, Bcf:						
Residential	9.0	8.4	10.9	10.8	11.1	12.6
Commercial	6.2	6.1	7.6	7.6	7.6	8.4
Industrial	1.5	2.5	3.5	3.5	4.2	6.6
End-use transportation	8.4	7.0	8.3	9.6	8.8	6.6
	25.1	24.0	30.3	31.5	31.7	34.2
Off-system transportation	2.2	3.1	3.1	4.8	1.1	2.8
	27.3	27.1	33.4	36.3	32.8	37.0
Customers at year-end:						
Residential	122,906	119,856	119,024	158,606	156,384	154,864
Commercial	16,448	16,177	16,282	21,929	22,229	21,431
Industrial	189	209	228	290	303	311
	139,543	136,242	135,534	180,825	178,916	176,606
Degree days	3,950	3,654	3,994	3,179	3,472	4,131
Percent of normal	98%	91%	100%	79%	87%	103%

(1) Shareholders' equity includes an accumulated comprehensive loss of $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 comprehensive income of $5.8 million in 2001 related to our cash flow hedges.

(2) 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

We operate in three segments: Exploration and Production, Natural Gas Distribution and Marketing, Transportation and Other. Our financial results depend on a number of factors, in particular natural gas and oil prices, 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. 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.

Our net income decreased from $35.3 million in 2001, or $1.38 per share on a fully diluted basis, to $14.3 million, or $0.55 per share in 2002. This decrease in net income was primarily a result of the negative impact of lower realized natural gas and oil prices on the operating income of our E&P segment. A decrease in the operating income for our gas distribution segment also negatively impacted our net income in 2002. In 2000, we reported a net loss of $46.7 million, which included one-time charges for a $109.3 million judgment we paid in connection with the Hales lawsuit and $2.0 million related to other litigation, a loss on the early retirement of debt, and a $3.2 million gain from the sale of our Missouri utility properties. Exclusive of these one-time charges and the gain on sale, net income for 2000 would have been $20.5 million, or $0.82 per share.

Revenues were $261.5 million in 2002, a decrease of 24% from $344.9 million in 2001, primarily reflecting lower realized natural gas and oil prices. Revenues in 2001 decreased 5% to $344.9 million from $363.9 million in 2000, reflecting lower volumes sold to unaffiliated parties by the marketing segment. This decline in volumes reflects our increased focus on marketing our own production and limiting the marketing of third-party volumes in an effort to reduce our credit risk.

RESULTS OF OPERATIONS

Exploration and Production

	Year ended December 31,		
	2002	2001	2000
Revenues (in thousands)	$122,207	$153,937	$110,920
Operating income (loss) (in thousands)	$ 36,048	$ 69,340	$ (70,584)(1)
Gas production (Bcf)	36.0	35.5	31.6
Oil production (MBbls)	682	719	676
Total production (Bcfe)	40.1	39.8	35.7
Average gas price per Mcf	$ 3.00	$ 3.85	$ 2.88
Average oil price per Bbl	$ 21.02	$ 23.55	$ 22.99
Average unit costs per Mcfe			
Lease operating expenses	$ 0.45	$ 0.45	$ 0.40
Taxes other than income taxes	$ 0.19	$ 0.17	$ 0.16
General & administrative expenses	$ 0.32	$ 0.34	$ 0.32
Full cost pool amortization	$ 1.16	$ 1.14	$ 1.06

(1) Includes a charge of $109.3 million paid by us in connection with the Hales judgment and a charge of $2.0 million related to other litigation. Excluding these unusual items, operating income for the E & P segment would have been $40.7 million for 2000.

Revenues, Operating Income and Production

Revenues. Our exploration and production revenues decreased 21% in 2002 to $122.2 million compared to $153.9 million in 2001. The decrease was primarily due to lower prices received for natural gas. Revenues increased 39% in 2001 to $153.9 million from $110.9 million in 2000. The increase was primarily due to increased natural gas and oil production and higher natural gas and oil prices.

Operating Income. Operating income from our exploration and production segment was $36.0 million in 2002 compared to $69.3 million in 2001, and $40.7 million in 2000, excluding the impact of the Hales judgment and other unusual items charged that year. The decrease in 2002 was primarily due to the decrease in revenues caused by the lower realized natural gas and oil prices. The increase in 2001 was due to an 11% increase in natural gas and oil production and higher prices realized, partially offset by increased operating costs and expenditures.

Production. Gas and oil production totaled 40.1 Bcfe in 2002, 39.8 Bcfe in 2001 and 35.7 Bcfe in 2000. 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, and the sale of our non-strategic Mid-Continent properties in the fourth quarter of 2002. The increase in 2001 production volumes resulted from successful exploration and development of our South Louisiana properties, the development of our Overton Field and increased production in the Arkoma Basin.

Gas sales to unaffiliated purchasers were 30.6 Bcf in 2002, up from 30.4 Bcf in 2001 and 23.8 Bcf in 2000. Sales to unaffiliated purchasers are primarily made under contracts that reflect current short-term prices and are subject to seasonal price swings. Intersegment sales to Arkansas Western were 5.4 Bcf in 2002, 5.1 Bcf in 2001 and 7.8 Bcf in 2000. The increase in 2002 intersegment sales resulted from increased deliveries to Arkansas Western under our baseload contracts. The decrease in sales in 2001 was caused by Arkansas Western's reduced supply requirements due to warmer weather and the sale of the utility's Missouri gas distribution properties in May 2000. Weather in 2002, as measured in degree days, 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 and was normal in 2000. Our gas production provided approximately 37% of the utility's requirements in 2002, 33% in 2001 and 42% in 2000.

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 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 was $3.00 per Mcf in 2002, $3.85 per Mcf in 2001, and $2.88 per Mcf in 2000. 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 $0.11 per Mcf in 2002, $0.31 per Mcf in 2001, and $1.04 per Mcf in 2000. In 2002, the price was reduced $0.03 per Mcf due to $1.1 million of basis differential ineffectiveness associated with our cash flow hedges. There was no significant ineffectiveness recorded in 2001. Additionally, we have historically received monthly demand charges related to sales made to our utility segment, which has increased the 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, 2002, we had hedges in place on 42.6 Bcf of gas production. Subsequent to December 31, 2002 and prior to February 14, 2003, we hedged an additional 3.0 Bcf of future gas production. At December 31, 2002 we had hedges in place on 240,000 barrels of future oil production. Subsequent to December 31, 2002 and prior to February 14, 2003, we hedged an additional 100,000 barrels of future oil production. As of February 14, 2003, we have hedged approximately 75% of our 2003 anticipated gas production level and 65% of our anticipated oil production level.

Disregarding the impact of hedges, we would normally expect the average price received for our gas production to be approximately $0.10 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 $21.02 per barrel for our oil production for the year ended December 31, 2002, down from $23.55 per barrel for 2001 and $22.99 per barrel for 2000. Our hedging activities lowered the average oil price $2.92 per barrel in 2002, $0.03 per barrel in 2001 and $6.39 per barrel in 2000. 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 $0.45 in 2002 and 2001, compared to $0.40 in 2000. Taxes other than income taxes per Mcfe were $0.19 in 2002, compared to $0.17 in 2001 and $0.16 in 2000. The increases in per unit lease operating expenses in 2002 and 2001 were due to increased workover expenses and changes in the geographic mix of production. Lease operating expense per unit should decrease in the future as a result of increased production from our Overton Field (lower average cost as compared to other areas), decreased production in Permian Basin properties (higher average cost as compared to other areas) and the sale of our Mid-Continent properties that had the highest average cost per unit of all operating areas. The increases in 2002 and 2001 taxes other than income taxes per Mcfe were due to increased severance and ad valorem taxes that resulted from generally higher commodity prices and from the changing mix of production among taxing jurisdictions. General and administrative expenses per Mcfe were $0.32 in 2002, compared to $0.34 in 2001 and $0.32 in 2000. The increase in general and administrative costs per Mcfe in 2001 was due primarily to increased legal costs related to the resolution of litigation (approximately $0.07 per Mcfe). Excluding the impact of these litigation costs in 2001, general and administrative costs in 2002 were higher per unit due to increased pension, insurance and salary costs.

Our full cost pool amortization rate averaged $1.16 per Mcfe for 2002, compared to $1.14 in 2001 and $1.06 in 2000. The rate increased in 2002 and 2001, due primarily to negative revisions of proved reserves that resulted from a decline in average gas prices and to a $6.6 million decline in 2001 in the balance of unevaluated costs excluded from amortization in the full cost pool. Unevaluated costs excluded from amortization have declined from $37.6 million at the beginning of 2000 to $25.5 million at the end of 2002.

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 to calculate the ceiling value of their reserves. At December 31, 2002, 2001 and 2000, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2002, our standardized measure was calculated based upon quoted market prices of $4.74 per Mcf for gas and $31.20 per barrel for oil, adjusted for market differentials. A decline in natural gas and oil prices from year-end 2002 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. We expect this divestiture to result in a decrease in our future average production costs per unit of production.

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 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 2002 and 2001 revenues, less operating costs and expenses, was $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, during both 2001 and 2000, the impact of inflation 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 has been decreasing in 2002 with the relative stabilization of commodity prices. Additionally, Southwestern has mitigated rising costs in certain situations by obtaining vendor commitments to multiple projects and by offering incentives to vendors for cost reduction efforts that directly impact the amount we pay for their services.

Natural Gas Distribution

The operating results of our gas distribution segment are highly seasonal and the extent and duration of heating weather significantly impacts the profitability of this segment, although we have a weather normalization clause that lessens the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The gas distribution segment's profitability is also dependent upon the timing and amount of regulatory rate increases that are filed with and approved by the APSC. For periods subsequent to allowed rate increases, our profitability is impacted by our ability to manage and control this segment's operating costs and expenses.

	Year Ended December 31,		
	2002	2001	2000(1)
	($ in thousands except for per Mcf amounts)		
Revenues	$115,850	$147,282	$151,234
Gas purchases	$ 66,486	$ 96,058	$ 93,992
Operating costs and expenses	$ 41,801	$ 40,878	$ 42,587
Operating income	$ 7,563	$ 10,346	$ 14,655
Deliveries (Bcf)			
Sales and end-use transportation	25.1	24.0	30.4
Off-system transportation	2.2	3.1	3.1
Average number of customers	136,747	134,041	152,773
Average sales rate per Mcf	$ 6.49	$ 8.26	$ 6.55
Heating weather - degree days	3,950	3,654	3,994
Percent of normal	98%	91%	100%

(1) Data for 2000 includes the operations of the Missouri properties through the sale date of May 31, 2000. Excluding the Missouri operations, operating income would have been $12.6 million in 2000.

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 decreased 21% in 2002 and decreased 3% in 2001. The decrease in 2002 was primarily due to a lower average sales rate caused by lower gas prices. The decrease in 2001 was due to the loss of revenues resulting from the sale of the utility's Missouri assets in May 2000 and the effects of warmer weather, partially offset by a higher average sales rate caused by higher gas prices. Weather during 2002 in the utility's service territory 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. Weather was normal in 2000.

Operating income for our utility systems decreased 27% in 2002 and 29% in 2001. The decrease in 2002 resulted from increased operating costs and expenses and reduced usage per customer due to customer conservation brought about by high gas prices in 2001. The decrease in 2001 operating income for this segment resulted from the full-year impact of the sale of the utility's Missouri assets, the effects of warmer weather that were not fully offset by the weather normalization clause in its tariffs and increased bad debt expense caused by record high natural gas prices experienced in the first part of 2001.

Deliveries and Rates

In 2002, Arkansas Western sold 16.7 Bcf to its customers at an average rate of $6.49 per Mcf, compared to 17.0 Bcf at $8.26 per Mcf in 2001 and 22.1 Bcf at $6.55 per Mcf in 2000. Additionally, Arkansas Western transported 8.4 Bcf in 2002, 7.0 Bcf in 2001 and 8.3 Bcf in 2000 for its end-use customers. The decrease in volumes sold in 2002 resulted from customer conservation brought about by high gas prices in 2001 and from several industrial customers moving from system supply to transportation, partially offset by customer growth. The decrease in volumes sold and transported in 2001 resulted from the sale of the utility's Missouri properties in 2000 and warmer weather. 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 9.9 Bcf in 2002, 9.5 Bcf in 2001 and 11.8 Bcf in 2000. The increase in deliveries in 2002 resulted from industrial growth in the region. The decline in deliveries in 2001 resulted from warmer heating weather and the sale of the utility's Missouri assets. Arkansas Western also transported 2.2 Bcf of gas through its gathering system in 2002 compared to 3.1 Bcf in both 2001 and 2000 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 2002 and 2001, and $0.10 per Mcf in 2000.

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% to 3% 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 Costs and Expenses

The changes in purchased gas costs for the gas distribution segment reflect volumes purchased, prices paid for supplies, the mix of purchases from various gas supply contracts (base load, swing and no-notice) and the sale of Missouri assets as discussed above. Operating costs and expenses increased in 2002 as compared to 2001 due to general inflationary effects and increased pension and insurance expenses. Other operating costs and expenses of the gas distribution segment decreased in 2001 as compared to 2000 due to the sale of the utility's Missouri assets. Operating costs in 2001 also included increased bad debt expense caused by high natural gas prices in the 2000-2001 winter heating season.

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 2002-2003 gas purchase year, SEECO successfully bid on gas supply packages representing approximately two-thirds of the requirements for Arkansas Western for 2003. 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. Act 1556 was modified by Act 324 of 2001 delaying the implementation of electric deregulation to not earlier than October 2003 and no later than October 2005. 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). Furthermore, legislation has been recently introduced seeking to repeal the deregulation of the retail sale of electricity. It is unknown what final legislation will be adopted or, if it is adopted, what its final form will be. If electric deregulation occurs in Arkansas, legislative or regulatory precedents may be set that would also affect natural gas utilities in the future. These issues may include further unbundling of services and the regulatory treatment of stranded costs.

Arkansas Western has historically maintained a substantial 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. The APSC has ten months to reach a decision on the amount of an allowed rate increase. As a result, any increase granted will become effective no later than September 2003. Arkansas Western's last rate increase was approved in December 1996 for the utility's Northwest region and in December 1997 for the Northeast region. The APSC approved increases of $5.1 million and $1.2 million, respectively. During 1999, the APSC initiated a proceeding in which it sought a $2.3 million reduction in the rates for the Northwest region. In late 1999, the APSC and Arkansas Western reached a settlement in which the Northwest region's rates were reduced by $1.4 million. The reduction was primarily due to a downward adjustment to the return on equity that the APSC had established in the 1996 rate case. 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. While Arkansas Western continues to experience customer growth and has controlled its costs, its return on investment has declined in recent years.

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 will be 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, Arkansas Western submitted its annual gas supply plan for the 2002-2003 heating season.

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, Transportation and Other

Operating income from the marketing, transportation and other segment, which includes income from real property held by our subsidiary, A.W. Realty Company, was $2.9 million in 2002, compared to $3.0 million in 2001 and $2.5 million in 2000. EBITDA for these segments was $2.8 million in 2002, compared with $2.4 million in 2001 and $3.0 million in 2000. For a further discussion of our EBITDA reconciliation, we refer you to "Business-Other Items-Reconciliation of Non-GAAP Measures."

Marketing

	Year Ended December 31,		
	2002	2001	2000
Revenues (in millions)	$ 131.1	$ 190.3	$ 207.7
Operating income (in millions)	$ 2.7	$ 2.7	$ 2.5
Gas volumes marketed (Bcf)	45.5	49.6	59.6

Our operating income from marketing was $2.7 million on revenues of $131.1 million in 2002, compared to $2.7 million on revenues of $190.3 million in 2001, and $2.5 million on revenues of $207.7 million in 2000. We marketed 45.5 Bcf in 2002, compared to 49.6 Bcf in 2001 and 59.6 Bcf in 2000. The decline in total volumes marketed in 2002 and 2001 resulted primarily from the decline in volumes marketed to third parties. This reduction reflects our increased 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, purchases from our exploration and production subsidiaries accounted for 67% in 2002, 66% in 2001 and 33% in 2000. 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

The marketing, transportation and other segment also manages our 25% interest in NOARK. At December 31, 2002, Arkansas Western had transportation contracts with Ozark Pipeline for 66.9 MMcf per day of firm capacity. These contracts expire in 2003 and are renewable annually thereafter until terminated with 180 days' notice. NOARK and Arkansas Western are currently renegotiating these contracts. Our recorded pre-tax loss from operations included in other income related to our NOARK investment was $0.3 million in 2002, $1.5 million in 2001, and $1.8 million in 2000. The improvements in operating results since 2000 result primarily from NOARK's ability to collect higher transportation rates on interruptible volumes. We believe that we will be able to continue to reduce the losses from NOARK 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 $71.0 million at December 31, 2002, and our share of the guarantee was $42.6 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 2002, and 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.

In January 2003, Ozark Pipeline sold a 28 mile portion of its pipeline system located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million. We received $2.5 million of cash proceeds from this sale and will record a gain of approximately $1.0 million in 2003.

Other Income, Costs and Expenses

Interest costs, net of capitalization, were down 9% in 2002 and down 4% in 2001, both as compared to prior years. Interest costs for 2000 have been restated from prior years' presentations to reflect costs incurred for the early extinguishment of debt. These costs were previously presented as a net-of-tax extraordinary item but have been reclassed for presentation purposes as required by SFAS No. 145. Interest costs were down in 2002 due to lower average borrowings and a lower average interest rate. A decrease in interest costs in 2001 that resulted from lower average borrowings, a lower average interest rate and the early extinguishment of debt costs discussed above, was partially offset by a lower level of capitalized interest related to our natural gas and oil properties. Interest capitalized decreased 7% in 2002 and 35% in 2001. The reductions in capitalized interest are primarily due to the level of costs excluded from amortization in our exploration and production segment.

Other income (expense) in 2002 resulted from our share of NOARK's results of operations, as discussed above, and interest costs on customer deposits in the gas distribution segment. Other income (expense) in 2001 resulted from our share of NOARK's results of operations, offset by interest income in the gas distribution segment related to under-recovered gas purchase costs. Other income in 2000 resulted from a $3.2 million gain on the sale of our Missouri gas distribution assets and gains from the sale of other miscellaneous assets, partially offset by our share of NOARK's results of operations.

The Hales judgment was the primary cause for our deferred tax benefit of $29.5 million in 2000. Excluding this impact, 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.

We recorded pension expense of $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. At December 31, 2002 our pension plans were underfunded and a liability of $5.6 million was recorded on the balance sheet. As a result of the underfunded status and actuarial data to be completed in early 2003, we expect to record pension expense of $3.0 million to $5.0 million in 2003. For further discussion of our pension plans, we refer you to Note 4 to the financial statements.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds and our revolving line of credit (discussed below under "Financing Requirements") as our primary sources of liquidity. We may borrow up to $125.0 million under our revolving credit facility from time to time. As of February 14, 2003, we had $106.1 million of indebtedness outstanding under the revolving credit facility. We expect our capital expenditures (discussed below under "Capital Expenditures") for 2003 to exceed the funds generated by our operations and the funds that may be available under our credit facility. In December 2002, we filed a shelf registration statement with the SEC pursuant to which we may from time to time during 2003, subject to market conditions, publicly offer equity, debt or other securities.

Net cash provided by operating activities was $77.6 million in 2002, compared to $144.6 million in 2001. In 2000, net cash used in operating activities was $53.2 million as a result of the Hales judgment and the impact of high year-end gas prices on working capital. 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. Net cash from operating activities provided 84% of our capital requirements for routine capital expenditures 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. If we are unable to raise funds in the capital markets in early 2003 as planned, we will be required to adjust our planned level of investment in capital projects in the E&P segment. This, in turn, could negatively impact growth in production volumes and cash flow from operations, which could ultimately affect our ability to meet the covenants contained in the indentures governing our public debt as well as our revolving credit facility agreement. We do not anticipate being unable to meet our covenants and commitments. See "Financing Requirements" for further discussion of our debt covenants.

Capital Expenditures

Capital expenditures totaled $92.1 million in 2002, $106.1 million in 2001, and $75.7 million in 2000. Our exploration and production segment expenditures included acquisitions of interests in natural gas and oil producing properties totaling $3.5 million in 2002, $7.3 million in 2001 and $7.4 million in 2000. Our reported capital investments in 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 exploration and development expenditures during 2002 and 2001, respectively.

	2002	2001	2000
		(in thousands)	
Exploration and production	$ 85,201	$ 98,964	$ 69,211
Gas distribution	6,115	5,347	5,994
Other	746	1,749	512
	$ 92,062	$ 106,060	$ 75,717

Capital investments planned for 2003 total approximately $145.6 million, consisting of $137.1 million for exploration and production, $7.7 million for gas distribution system improvements and $0.8 million for general purposes. We expect that this level of capital investments in 2003 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 finance improvements necessary due to normal customer growth in our gas distribution segment. As discussed above, our 2003 capital investment program is expected to be funded through cash flow from operations, our revolving credit facility, and, subject to market conditions, one or more possible public offerings of equity, debt or other securities. We may adjust our level of future capital investments dependent upon our ability to consummate such offerings and 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 and 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%. At December 31, 2002 and 2001, the outstanding principal amount of these notes was $71.0 million and $73.0 million, respectively. Our share of the guarantee was $42.6 million and $43.8 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 2002, and advanced $1.4 million in 2001 primarily for debt service.

Our share of the results of operations included in other income related to our NOARK investment were losses of $0.3 million in 2002, $1.5 million in 2001, and $1.8 million in 2000. The improvements in operating results since 2000 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 (see Note 7 of the financial statements for additional discussion).

NOARK's assets and liabilities as of December 31, 2002 and 2001 are as follows:

	2002	2001
	(in thousands)	
Current assets	$ 15,730	$ 8,363
Noncurrent assets	169,970	175,299
	$ 185,700	$ 183,662
Current liabilities	$ 7,631	$ 7,403
Long-term debt	69,000	71,000
Partners' capital	109,069	105,259
	$ 185,700	$ 183,662

NOARK's results of operations for 2002, 2001 and 2000 are summarized below:

	2002	2001	2000
		(in thousands)	
Operating revenues	$ 75,959	$ 81,662	$ 73,633
Pre-tax net income (loss)	$ 3,011	$ (1,047)	$ (1,391)

Contractual Obligations and Contingent Liabilities and Commitments

We have assumed various contractual obligations and contingent commitments in the normal course of our operations and financing activities. Significant contractual obligations at December 31, 2002 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	$ 342,400	$ —	$ 242,400	$ —	$ 100,000
Operating leases(1)	2,653	729	1,428	496	—
Unconditional purchase obligations(2)	—	—	—	—	—
Demand charges(3)	17,312	7,458	3,642	2,485	3,727
Other long-term obligations(4)	1,860	1,860	—	—	—
	$ 364,225	$ 10,047	$ 247,470	$ 2,981	$ 103,727

(1) We lease office space in Houston, Texas, office space in Tulsa, Oklahoma, and approximately twenty vehicles under operating leases expiring through 2006.

(2) Our utility segment has volumetric commitments for the purchase of gas under competitive bid packages and wellhead contracts. Volumetric purchase commitments at December 31, 2002 totaled 3.1 Bcf, comprised of 1.3 Bcf in less than one year, 1.0 Bcf in one to three years, .5 Bcf in three to five years and .3 Bcf in more than five years. Our volumetric purchase commitments are priced 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 demand charges on firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers.

(4) Our significant other contractual obligations for 2003 include approximately $0.8 million of land leases, approximately $0.5 million for drilling rig commitments and approximately $0.6 of various information technology support agreements.

We refer you to "Financing Requirements" below for a discussion of the terms of our long-term debt.

Contingent Liabilities or 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, is expected to result in an increase in pension expense and our required funding of the plans for 2003. At December 31, 2002 we recorded an accrued pension benefit liability of $5.6 million. As a result of the underfunded status and actuarial data to be completed in early 2003, we expect to record pension expense of $3.0 million to $5.0 million in 2003. See Note 4 to the financial statements 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, 2002 the principal outstanding for these notes was $71.0 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 $342.4 million at December 31, 2002 and $350.0 million at December 31, 2001. In July 2001, we arranged an unsecured revolving credit facility with a group of banks to replace our previous short-term credit facility that was put in place in July 2000. The revolving credit facility has a maximum capacity of $125.0 million and expires in July 2004. At December 31, 2002, we had $117.4 million of outstanding debt under our revolving credit facility, with $7.6 million of borrowing availability. The interest rate on the new facility is calculated based upon our debt rating. We are currently paying 150 basis points over LIBOR. We have also entered into interest rate swaps for calendar year 2003 that allow us to pay a fixed average interest rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of our outstanding revolving debt.

Our revolving credit facility contains covenants, which impose certain restrictions on us. Under the credit agreement at December 31, 2002, we may not issue total debt in excess of 70% of our total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of EBITDA to interest expense at 3.75 or above. Effective March 31, 2003, the percentage of debt to total capital covenant decreases to 65% and the minimum ratio of EBITDA to interest expense covenant increases to 4.0. These covenants continue to change over the term of the credit facility and generally become more restrictive. We were in compliance with our debt agreements at December 31, 2002. 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. Our publicly traded notes are rated BBB by Standard and Poor's and Ba2 by Moody's. During 2002, Moody's downgraded our public debt from our previous Baa3 rating. The interest rate under the revolving credit facility increased 12.5 basis points in July 2002 as the result of the downgrade of our public debt by Moody's. Further downgrades of our public debt could increase the costs of funds under our revolving credit facility.

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.

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 $42.6 million at December 31, 2002. We did not advance any funds to NOARK in 2002. In 2001, we advanced $1.4 million to NOARK to fund its share of debt service payments. If NOARK is unable to generate sufficient cash in the future to service our 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 2002, our capital structure consisted of 65.9% debt (excluding our several guarantee of NOARK's obligations) and 34.1% equity, with a ratio of EBITDA to interest expense of 4.65. 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, 2002 balance sheet includes an accumulated other comprehensive loss of $14.0 million related to our hedging activities that is required to be recorded under the provisions of SFAS No. 133. This amount is based on current market values of our hedges at December 31, 2002 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 SFAS No. 133 as well as the non-cash impact of any full cost ceiling write downs. Our capital structure, including our several guarantee of NOARK's obligations, would be 66.8% debt and 33.2% equity at December 31, 2002 without consideration of the accumulated other comprehensive loss related to SFAS No. 133. As part of our strategy to insure cash flow to fund our operations and meet the restrictive covenant tests under our debt agreements, we have hedged approximately 75% of our expected 2003 gas production and 65% of our expected 2003 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 2003 and our capital expenditure plans do not change from current expectations, we do not expect to materially reduce our long-term debt in 2003. If commodity prices significantly decrease, we may incur additional long-term debt to fund our capital expenditure plans or we may modify our capital expenditure plans.

We refer you to "Business-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 operating 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 facility described above. We had positive working capital of $1.6 million at the end of 2002 and $21.7 million at the end of 2001. Current assets decreased by 18% in 2002 and current liabilities increased 4%. The decrease in current assets at December 31, 2002 was due primarily to decreases in amounts recorded in accordance with SFAS No. 133 for derivative activities, and decreases in accounts receivable, inventories and cash. Decreases in accounts payable and over-recovered purchased gas costs in current liabilities were more than offset by increases in amounts recorded as current liabilities for derivative activities. At December 31, 2002, we had over-recovered purchased gas costs of $5.7 million.

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 oil or natural gas prices, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on December 31, 2002, 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 prepared by our reservoir engineers.

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 SFAS No. 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 Accounting

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 2002, the discount rate assumed is 6.8% and the expected return assumed is 9.0%. This compares to a discount rate of 7.0% and an expected return of 9.0% used in 2001.

Using the assumed rates discussed above, we recorded pension expense of $0.9 million in 2002 and a credit to expense of $0.1 million in 2001. We reflected a pension liability of $5.6 million at December 31, 2002 and a prepaid benefit cost of $4.9 million at December 31, 2001. Assuming a 1% change in the 2002 rates (lower discount rate and lower rate of return), we would have recorded pension expense of $1.7 million in 2002, and recorded an accrued pension liability of $10.7 million at December 31, 2002.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the exploration and production 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 $3.10 at December 31, 2002 and 10.1 Bcf at $3.05 at December 31, 2001.

The gas in inventory for the exploration and production 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 exploration and production 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 prospectus supplement and accompanying prospectus 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 4% of accounts receivable. 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, 2002 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. We have entered into interest rate swaps for the calendar year 2003 that allow us to pay a fixed average interest rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of our outstanding revolving debt.

	Expected Maturity Date ($ in millions)							Fair Value
	2003	2004	2005	2006	2007	Thereafter	Total	12/31/02
Fixed Rate	$ —	$ —	$ 125.0	$ —	$ —	$ 100.0	$ 225.0	$ 222.6
Average Interest Rate	—	—	6.70%	—	—	7.46%	7.04%	—
Variable Rate	$ —	$ 117.4	$ —	$ —	$ —	$ —	$ 117.4	$ 117.4
Average Interest Rate	—	3.23%	—	—	—	—	3.23%	—

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 receives 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. The table presents the notional amount in Bcf and MBbls, the weighted average contract prices, and the total dollar contract amount by expected maturity dates. The "Carrying Amount" for the contract amounts is calculated as the contractual payments for the quantity of gas or oil to be exchanged under futures contracts and does not represent amounts recorded in our financial statements. The "Fair Value" represents values for the same contracts using comparable market prices at December 31, 2002. At December 31, 2002, the "Carrying Amount" exceeded the "Fair Value" of these financial instruments by $20.5 million.

	Expected Maturity Date			
	2003		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Production and Marketing				
Natural Gas				
Swaps with a fixed-price receipt				
Contract volume (Bcf)	13.3		7.2	
Weighted average price per Mcf	$ 3.47		$ 4.01	
Contract amount (in millions)	$ 46.2	$ 31.3	$ 28.8	$ 27.0
Price collars				
Contract volume (Bcf)	15.9		8.0	
Weighted average floor price per Mcf	$ 3.16		$ 3.50	
Contract amount of floor (in millions)	$ 50.1	$ 50.8	$ 28.0	$ 30.2
Weighted average ceiling price per Mcf	$ 4.84		$ 4.65	
Contract amount of ceiling (in millions)	$ 76.7	$ 71.3	$ 37.2	$ 33.2
Oil				
Swaps with a fixed-price receipt				
Contract volume (MBbls)	240		—	
Weighted average price per Bbl	$ 25.40		$ —	
Contract amount (in millions)	$ 6.1	$ 5.7	$ —	$ —
Natural Gas Purchases				
Swaps with a fixed-price payment				
Contract volume (Bcf)	2.7		—	
Weighted average price per Mcf	$ 3.42		$ —	
Contract amount (in millions)	$ 9.2	$ 12.3	$ —	$ —

At December 31, 2002, we had financial instruments that are sensitive to changes in interest rates. This $40.0 million of notional interest rate swaps have an average fixed rate of 2.3%. Their carrying amount of $1.0 million is calculated as the contractual payments for interest on the notional amount to be exchanged under futures contracts and does not represent amounts recorded in our financial statements. The fair value of $0.6 million represents the value for the same contracts using comparable market prices at December 31, 2002. At December 31, 2002, the "Carrying Amount" exceeded the "Fair Value" of these interest rate swaps by $0.4 million.

Subsequent to December 31, 2002 and prior to February 14, 2003, we entered into additional derivative contracts to hedge gas and oil production sales. A price collar hedge on 3.0 Bcf of 2003 gas production sales has a floor of $4.00 per Mcf and a ceiling of $5.97 per Mcf. A fixed price swap on oil production of 100 MBbls in 2003 will yield $29.40 per barrel.

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 accountants, PricewaterhouseCoopers LLP. In accordance with auditing standards generally accepted in the United States, the independent accountants obtained a sufficient understanding of our internal controls to plan their audit and determine the nature, timing, and extent of other tests to be performed.

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 accountants have direct access to the Audit Committee and periodically meet with the Audit Committee without management representatives present.

REPORT OF INDEPENDENT ACCOUNTANTS

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, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, 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."

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 5, 2003

STATEMENTS OF OPERATIONS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2002	2001	2000
	(in thousands, except share/per share amounts)		
Operating revenues:			
Gas sales	$ 198,108	$ 248,952	$ 200,269
Gas marketing	41,709	71,839	137,234
Oil sales	14,340	16,932	15,537
Gas transportation and other	7,345	7,204	10,843
	261,502	344,927	363,883
Operating costs and expenses:			
Gas purchases - utility	48,388	68,161	58,669
Gas purchases - marketing	37,927	68,010	133,221
Operating expenses	38,154	39,035	34,808
General and administrative expenses	26,446	25,073	24,982
Unusual items	—	—	111,288
Depreciation, depletion and amortization	53,992	52,899	45,869
Taxes, other than income taxes	10,090	9,080	8,515
	214,997	262,258	417,352
Operating income (loss)	46,505	82,669	(53,469)
Interest expense:			
Interest on long-term debt	21,664	23,920	24,089
Other interest charges	1,285	1,374	3,047
Interest capitalized	(1,483)	(1,595)	(2,447)
	21,466	23,699	24,689
Other income (expense)	(566)	(799)	1,997
Income (loss) before income taxes and minority interest	24,473	58,171	(76,161)
Minority interest in partnership	(1,454)	(930)	—
Income (loss) before income taxes	23,019	57,241	(76,161)
Provision (benefit) for income taxes			
Current	—	—	—
Deferred	8,708	21,917	(29,474)
	8,708	21,917	(29,474)
Net income (loss)	$ 14,311	$ 35,324	$ (46,687)
Earnings (loss) per share:			
Basic	$ .57	$ 1.40	$ (1.86)
Diluted	$ .55	$ 1.38	$ (1.86)
Weighted average common shares outstanding:			
Basic	25,226,580	25,198,105	25,043,586
Diluted	26,052,238	25,601,110	25,043,586

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

BALANCE SHEETS

Southwestern Energy Company and Subsidiaries

	December 31, 2002	December 31, 2001
	(in thousands)	
ASSETS		
Current assets		
Cash	$ 1,690	$ 3,641
Accounts receivable	42,115	42,763
Inventories, at average cost	24,735	26,606
Hedging asset - SFAS No. 133	3,130	9,381
Regulatory asset - hedges	—	5,817
Other	4,468	4,996
Total current assets	76,138	93,204
Investments	15,287	15,538
Property, plant and equipment, at cost		
Gas and oil properties, using the full cost method, including $25,494,000 in 2002 and $21,102,000 in 2001 excluded from amortization	1,030,300	970,680
Gas distribution systems	197,473	192,784
Gas in underground storage	32,395	32,046
Other	31,391	30,110
	1,291,559	1,225,620
Less: Accumulated depreciation, and amortization	659,398	605,790
	632,161	619,830
Other assets	16,576	14,551
	$ 740,162	$ 743,123
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 29,881	$ 41,644
Taxes payable	5,213	4,400
Interest payable	2,513	2,653
Customer deposits	4,999	4,845
Hedging liability - SFAS No. 133	20,409	6,990
Regulatory liability - hedges	3,130	—
Over-recovered purchased gas costs	5,697	8,184
Other	2,715	2,752
Total current liabilities	74,557	71,468
Long-term debt	342,400	350,000
Other liabilities		
Deferred income taxes	116,591	122,381
Other	16,671	3,187
	133,262	125,568
Commitments and contingencies		
Minority interest in partnership	12,455	13,001
Shareholders' equity		
Common stock, $0.10 par value; authorized 75,000,000 shares, issued 27,738,084 shares	2,774	2,774
Additional paid-in capital	19,130	19,764
Retained earnings	197,988	183,677
Accumulated other comprehensive income (loss)	(17,358)	5,763
	202,534	211,978
Less: Common stock in treasury, at cost, 1,793,456 shares in 2002 and 2,261,766 shares in 2001	19,981	25,196
Unamortized cost of restricted shares issued under stock incentive plan, 498,123 shares in 2002 and 416,537 shares in 2001	5,065	3,696
	177,488	183,086
	$ 740,162	$ 743,123

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,		
	2002	2001	2000
		(in thousands)	
Cash flows from operating activities			
Net income (loss)	$ 14,311	$ 35,324	$ (46,687)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	56,399	54,505	48,686
Deferred income taxes	8,708	21,917	(29,474)
Ineffectiveness of cash flow hedges	1,121	—	—
Equity in loss of NOARK partnership	251	1,484	1,767
Gain on sale of Missouri utility assets	—	—	(3,209)
Minority interest in partnership	(1,015)	(533)	—
Change in assets and liabilities:			
Accounts receivable	648	34,278	(36,693)
Income taxes receivable	—	—	85
Under/over-recovered gas costs	(2,487)	21,126	(14,104)
Inventories	1,871	(9,606)	2,290
Accounts payable	(2,883)	(12,660)	22,156
Other current assets and liabilities	650	(1,252)	1,980
Net cash provided by (used in) operating activities	77,574	144,583	(53,203)
Cash flows from investing activities			
Capital expenditures	(92,062)	(106,060)	(75,717)
Sale of Missouri utility assets	—	—	32,000
Sale of natural gas and oil properties	26,415	—	13,651
Investment in NOARK partnership	—	(1,449)	(3,250)
(Increase) decrease in gas stored underground	(349)	(4,179)	845
Other items	1,527	826	(1,066)
Net cash used in investing activities	(64,469)	(110,862)	(33,537)
Cash flows from financing activities			
Payments on revolving long-term debt	(204,100)	(248,500)	(247,900)
Borrowings under revolving long-term debt	196,500	202,500	363,700
Change in bank drafts outstanding	(9,880)	—	—
Proceeds from exercise of common stock options	1,955	—	—
Retirement of notes and payments on long-term debt	—	—	(24,910)
Contribution from minority interest owner in partnership	469	13,534	—
Dividends paid	—	—	(3,004)
Net cash provided by (used in) financing activities	(15,056)	(32,466)	87,886
Increase (decrease) in cash	(1,951)	1,255	1,146
Cash at beginning of year	3,641	2,386	1,240
Cash at end of year	$ 1,690	$ 3,641	$ 2,386

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		Additional Paid-In Capital	Retained Earnings	Treasury Stock	Unamortized Restricted Stock Awards	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount						
Balance at December 31, 1999	27,738	$ 2,774	$ 20,732	$ 198,044	$ (30,083)	$ (1,111)	$ —	$ 190,356
Net income	—	—	—	(46,687)	—	—	—	(46,687)
Issuance of restricted stock	—	—	(554)	—	1,720	(1,114)	—	52
Cancellation of restricted stock	—	—	42	—	(122)	80	—	—
Amortization of restricted stock	—	—	—	—	—	574	—	574
Cash dividends declared ($0.12 per share)	—	—	—	(3,004)	—	—	—	(3,004)
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 SFAS No. 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	—	—	—	—	—	646	—	646
Balance at December 31, 2001	27,738	2,774	19,764	183,677	(25,196)	(3,696)	5,763	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 income (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	—	—	—	—	—	1,257	—	1,257
Balance at December 31, 2002	27,738	$ 2,774	$ 19,130	$197,988	$ (19,981)	$ (5,065)	$ (17,358)	$ 177,488

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,		
	2002	2001	2000
		(in thousands)	
Balance, beginning of year	$ 5,763	$ —	$ —
Cumulative effect of adoption of SFAS No. 133	—	(36,963)	—
Current period reclassification to earnings	4,735	22,874	—
Current period change in derivative instruments	(24,498)	19,852	—
Current period change in pension liability	(3,358)	—	—
Balance, end of year	$ (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, 2002, 2001 and 2000

(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, Louisiana, Texas, 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 (SFAS) 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.

Unusual Items

In June 2000, the Company reported that the Arkansas Supreme Court ruled to affirm the 1998 decision of the Sebastian County Circuit Court awarding $109.3 million in a class action to royalty owners of SEECO, Inc. (Hales judgment). The Company fully satisfied the judgment and the Circuit Court in Sebastian County issued an order in complete satisfaction of the judgment effective July 18, 2000. Additionally, the Company incurred an unusual charge of $2.0 million during 2000 related to other litigation.

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, 2002, 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, 2002 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.

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 1.8% to 5.8%.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 5 to 35 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, both stated at average cost. 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 exploration and production 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.

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 level included in the base 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.

The Company filed a rate increase request in November 2002 and expects the Arkansas Public Service Commission to rule on this request for a rate increase that would be effective no earlier than September 2003.

Gas Production 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, 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. At December 31, 2001, the Company had overproduction of 1.6 Bcf valued at $4.3 million and underproduction of 1.7 Bcf valued at $4.9 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 carry forward at December 31, 2002 was $117.2 million with an expiration date of December 31, 2020.

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. Gains or losses from commodity swap agreements and options that do not qualify for accounting treatment as hedges would be recognized currently as other income or expense. See Note 8 for a discussion of the Company's hedging activities and the effects of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

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 2,602,800 shares with an average exercise price of $9.79 outstanding at December 31, 2000 that, due to the Company's net loss for 2000, would have had an anti-dilutive effect and were, therefore, not considered. The Company had 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 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.

Dividend on Common Stock

As a result of the adverse Hales judgment in June 2000, the Company has indefinitely suspended payment of quarterly dividends on its common stock. Additionally, at the present time the payment of dividends is prohibited under the Company's current revolving credit facility.

Loss on Retirement of Debt

During 2002, the Company adopted Statement of Financial Accounting Statement No. 145, "Recessions of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13, and Technical Connections." Under the provisions of this standard, gains and losses from extinguishment of debt generally will no longer be classified as extraordinary items in the statement of operations. Accordingly, the Company's loss on early retirement of debt of $1.5 million in the year ended December 31, 2000, which was previously presented as a net of tax extraordinary item, has been reclassified in the accompanying financial statements and presented as a component of interest expense. This reclassification had no impact on the Company's financial position, net income or cash flows.

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 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, 2002, 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 FASB Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	For the years ended December 31,		
	2002	2001	2000
Net income, as reported	$ 14,311	$ 35,324	$(46,687)
Add back: Amortization of restricted stock	781	399	352
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(1,798)	(1,350)	(1,109)
Pro forma net income	$ 13,294	$ 34,373	$(47,444)
Earnings per share:			
Basic-as reported	$ 0.57	$ 1.40	$ (1.86)
Basic-pro forma	$ 0.53	$ 1.36	$ (1.90)
Diluted-as reported	$ 0.55	$ 1.38	$ (1.86)
Diluted-pro forma	$ 0.51	$ 1.34	$ (1.90)

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 45.6% for 2002, 46.4% for 2001 and 44.0% for 2000; risk-free interest rate of 3.4% for 2002, 4.8% for 2001 and 6.0% for 2000; and expected lives of 6 years for all option grants. The fair values of the option grants for each of the years 2002, 2001 and 2000 were $1.9 million, $0.9 million and $2.6 million, respectively.

Reclassifications

Certain amounts in the prior years' financial statements have been reclassified to conform with the 2002 presentation. These reclassifications had no impact on the Company's financial position, net income or cash flows.

(2) DEBT

Debt balances as of December 31, 2002 and 2001 consisted of the following:

	2002	2001
	(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 (2.89% at December 31, 2002) unsecured revolving credit arrangements	117,400	125,000
Total long-term debt	$ 342,400	$ 350,000

In July 2001, the Company arranged a new unsecured revolving credit facility with a group of banks to replace an existing short-term credit facility that was put in place in July 2000. The revolving credit facility has a current capacity of $125 million and a three-year term. The interest rate on the facility is 150 basis points over the current London Interbank Offered Rate (LIBOR). The credit facility contains covenants, which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 70% 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 at least 3.75 or higher through December 31, 2002. These covenants change over the term of the credit facility and generally become more restrictive. The Company was in compliance with its debt agreements at December 31, 2002. The Company has entered into interest rate swaps for calendar year 2003 that allow the Company to pay an average fixed interest rate of 3.8% (based upon current rates under the revolving credit facility) on $40 million of its outstanding revolving debt.

There are no aggregate maturities of long-term debt for each of the years ending December 31, 2003, 2006 and 2007. For each of the years ended December 31, 2004 and 2005, the aggregate maturity is $117.4 million and $125.0 million, respectively. Total interest payments were $21.5 million in 2002, $24.4 million in 2001, and $23.6 million in 2000.

(3) INCOME TAXES

The provision (benefit) for income taxes included the following components:

	2002	2001 (in thousands)	2000
Federal:			
Current	$ —	$ —	$ —
Deferred	8,048	19,461	(24,202)
State:			
Current	—	—	—
Deferred	779	2,575	(5,153)
Investment tax credit amortization	(119)	(119)	(119)
Provision (benefit) for income taxes	$ 8,708	$ 21,917	$ (29,474)

The provision (benefit) for income taxes was an effective rate of 37.8% in 2002, 38.3% in 2001, and 38.7% in 2000. The following reconciles the provision (benefit) for income taxes included in the consolidated statements of operations with the provision (benefit) which would result from application of the statutory federal tax rate to pre-tax financial income:

	2002	2001 (in thousands)	2000
Expected provision (benefit) at federal statutory rate of 35%	$ 8,055	$ 20,034	$ (26,656)
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	506	1,674	(3,349)
Other	147	209	531
Provision (benefit) for income taxes	$ 8,708	$ 21,917	$ (29,474)

The components of the Company's net deferred tax liability as of December 31, 2002 and 2001 were as follows:

	2002 (in thousands)	2001
Deferred tax liabilities:		
Differences between book and tax basis of property	$ 156,208	$ 142,007
Stored gas	4,337	8,037
Prepaid pension costs	—	1,908
Book over tax basis in partnerships	11,324	11,148
Other	4,421	6,694
	176,290	169,794
Deferred tax assets:		
Accrued compensation	$ 525	$ 721
Alternative minimum tax credit carryforward	3,026	3,026
Accrued pension costs	2,102	—
Cash flow hedges - SFAS No. 133	8,764	—
Net operating loss carryforward	45,952	41,922
Other	406	2,939
	60,775	48,608
Net deferred tax liability	$ 115,515	$ 121,186

There were no income tax payments in 2002 and 2001. Total income tax payments of $0.5 million were made in 2000. The Company's net operating loss carryforward at December 31, 2002, was $117.2 million with an expiration date of December 31, 2020. 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, 2002.

(4) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." 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, 2002 and 2001:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
	(in thousands)			
Change in benefit obligations:				
Benefit obligation at January 1	$ 60,925	$ 56,571	$ 2,099	$ 2,011
Service cost	1,967	1,318	90	71
Interest cost	3,655	4,133	170	138
Actuarial loss (gain)	(6,762)	3,338	958	10
Benefits paid	(5,091)	(4,435)	(161)	(131)
Benefit obligation at December 31	$ 54,694	$ 60,925	$ 3,156	$ 2,099
Change in plan assets:				
Fair value of plan assets at January 1	$ 59,010	$ 66,283	$ 672	$ 573
Actual return on plan assets	(11,959)	(2,478)	(7)	2
Employer contributions	13	18	228	228
Benefit payments	(5,091)	(4,435)	(161)	(131)
Amount transferred	—	(378)	—	—
Fair value of plan assets at December 31	$ 41,973	$ 59,010	$ 732	$ 672
Funded status:				
Funded status at December 31	$ (12,721)	$ (1,916)	$ (2,424)	$ (1,427)
Unrecognized net actuarial (gain) loss	12,643	2,288	1,249	322
Unrecognized prior service cost	4,056	4,514	—	—
Additional minimum liability	(9,580)	—	—	—
Unrecognized transition obligation	—	—	860	946
Prepaid (accrued) benefit cost	$ (5,602)	$ 4,886	$ (315)	$ (159)

At December 31, 2002, amounts recognized with respect to the Company's defined benefit pension plan included an accrued liability of $5.6 million, an intangible asset of $4.1 million and accumulated other comprehensive income of $5.5 million ($3.4 million after tax). Amounts recognized at December 31, 2002 associated with the Company's other postretirement benefits was an accrued liability of $.3 million.

The Company's supplemental retirement plan has an accumulated benefit obligation in excess of plan assets. The plan's accumulated benefit obligation was $374,000 and $326,000 at December 31, 2002 and 2001, respectively. There are no plan assets in the supplemental retirement plan due to the nature of the plan.

Net periodic pension and other postretirement benefit costs include the following components for 2002, 2001 and 2000:

	Pension Benefits			Other Postretirement Benefits		
	2002	2001	2000	2002	2001	2000
	(in thousands)					
Service cost	$ 1,967	$ 1,318	$ 1,682	$ 90	$ 71	$ 85
Interest cost	3,655	4,133	4,509	170	138	268
Expected return on plan assets	(5,165)	(5,829)	(6,190)	(41)	(34)	(39)
Amortization of transition obligation	—	(36)	(183)	86	86	103
Recognized net actuarial (gain) loss	7	(97)	(142)	79	19	63
Amortization of prior service cost	457	451	451	—	—	—
	$ 921	$ (60)	$ 127	$ 384	$ 280	$ 480

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 for 2002 and 2001 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
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%	4.50%	n/a	n/a

For measurement purposes, a 12% annual rate of increase in the per capita cost of covered medical benefits and a 7.5% annual rate of increase in the per capita cost of dental benefits was assumed for 2003. These rates were assumed to gradually decrease to 5% over seven years and remain at that level thereafter.

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	$ 26	$ (32)
Effect on postretirement benefit obligation	$ 369	$ (315)

(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:

	2002	2001	2000
		(in thousands)	
Sales	$ 122,207	$ 153,937	$ 110,920
Production (lifting) costs	(25,514)	(24,393)	(20,229)
Depreciation, depletion and amortization	(47,680)	(46,530)	(39,048)
	49,013	83,014	51,643
Income tax expense	(18,474)	(31,519)	(20,351)
Results of operations	$ 30,539	$ 51,495	$ 31,292

The results of operations shown above exclude unusual items in 2000 and overhead and interest costs in all years. 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 2002, 2001 and 2000:

	2002	2001	2000
		(in thousands)	
Proved property acquisition costs	$ 3,481	$ 7,323	$ 7,428
Unproved property acquisition costs	4,984	4,482	5,941
Exploration costs	24,552	23,490	27,853
Development costs	51,818	63,103	27,519
Capitalized costs incurred	$ 84,835	$ 98,398	$ 68,741
Amortization per Mcf equivalent	$ 1.16	$ 1.14	$ 1.06

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $1.5 million, $1.6 million and $2.4 million during 2002, 2001 and 2000, 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 $9.5 million, $8.3 million and $7.3 million during 2002, 2001 and 2000, 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, 2002 and 2001:

	2002	2001
	(in thousands)	
Proved properties	$ 1,004,806	$ 944,502
Unproved properties	25,494	26,178
Total capitalized costs	1,030,300	970,680
Less: Accumulated depreciation, depletion and amortization	549,419	502,882
Net capitalized costs	$ 480,881	$ 467,798

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2002. Of the total, approximately $13.5 million is invested in Louisiana. The majority of Louisiana costs are related to seismic projects that will be evaluated over several years as the seismic data is interpreted and the acreage is explored. 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.

	2002	2001	2000	Prior	Total
			(in thousands)		
Property acquisition costs	$ 6,959	$ 2,045	$ 1,438	$ 1,647	$ 12,089
Exploration costs	3,821	635	1,722	3,931	10,109
Capitalized interest	426	289	734	1,847	3,296
	$11,206	$ 2,969	$ 3,894	$ 7,425	$25,494

(6) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2002, 2001 and 2000:

	2002		2001		2000	
	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	355,813	7,704	331,754	8,130	307,523	7,859
Revisions of previous estimates	1,110	234	(21,598)	(979)	5,357	(22)
Extensions, discoveries, and other additions	73,803	553	77,187	1,272	53,389	1,347
Production	(35,972)	(682)	(35,477)	(719)	(31,602)	(676)
Acquisition of reserves in place	6,538	15	4,325	21	8,100	82
Disposition of reserves in place	(26,678)	(1,040)	(378)	(21)	(11,013)	(460)
Proved reserves, end of year	374,614	6,784	355,813	7,704	331,754	8,130
Proved, developed reserves:						
Beginning of year	281,461	6,429	270,830	7,100	250,290	7,154
End of year	286,276	5,633	281,461	6,429	270,830	7,100

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves" (standardized measure) is a disclosure required by SFAS No. 69, "Disclosures About Oil and Gas Producing Activities." 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 2002 and by K & A Energy Consultants, Inc. with respect to 2001 and 2000.

Following is the standardized measure relating to proved gas and oil reserves at December 31, 2002, 2001 and 2000:

	2002	2001 (in thousands)	2000
Future cash inflows	$ 1,951,454	$ 1,095,843	$ 3,366,304
Future production costs	(466,742)	(313,357)	(461,808)
Future development costs	(62,206)	(57,136)	(44,609)
Future income tax expense	(420,336)	(182,103)	(974,273)
Future net cash flows	1,002,170	543,247	1,885,614
10% annual discount for estimated timing of cash flows	(500,571)	(235,087)	(990,472)
Standardized measure of discounted future net cash flows	$ 501,599	$ 308,160	$ 895,142

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 2002, 2001 and 2000:

	2002	2001	2000
		(in thousands)	
Standardized measure, beginning of year	$ 308,160	$ 895,142	$ 262,075
Sales and transfers of gas and oil produced, net of production costs	(96,693)	(129,544)	(90,691)
Net changes in prices and production costs	284,277	(979,522)	837,691
Extensions, discoveries, and other additions, net of future production and development costs	137,105	102,832	259,212
Acquisition of reserves in place	11,269	5,406	33,032
Revisions of previous quantity estimates	4,870	(24,966)	20,178
Accretion of discount	39,451	133,136	38,076
Net change in income taxes	(106,177)	349,862	(317,527)
Changes in production rates (timing) and other	(80,663)	(44,186)	(146,904)
Standardized measure, end of year	$ 501,599	$ 308,160	$ 895,142

(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 $15.2 million at December 31, 2002, and $15.5 million at December 31, 2001 and 2000, including advances of $1.4 million made during 2001 and $3.3 million made during 2000. The Company did not advance any funds to NOARK during 2002. The prior advances were made primarily to service NOARK's long-term debt. See Note 11 for further discussion of NOARK's funding requirements and the Company's investment in NOARK.

The Company recorded pre-tax losses of $0.3 million, $1.5 million and $1.8 million for 2002, 2001 and 2000, respectively, for its share of NOARK's results of operations. 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, 2002 and 2001 were as follows:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash	$ 1,690	$ 1,690	$ 3,641	$ 3,641
Customer deposits	$ 4,999	$ 4,999	$ 4,845	$ 4,845
Long-term debt	$ 342,400	$ 340,048	$ 350,000	$ 356,179
Commodity and interest hedges asset (liability)	$ (20,875)	$ (20,875)	$ 3,246	$ 3,246

Derivatives and Risk Management

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and SFAS No. 138, was adopted by the Company on January 1, 2001. SFAS No. 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.

Upon adoption of SFAS No. 133 on January 1, 2001, the Company recorded a transition obligation of $60.6 million related to cash flow hedges in place that are intended to reduce the volatility in commodity prices for the Company's forecasted natural gas and oil production. 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 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. The Company recorded $1.1 million in 2002 related to basis differential ineffectiveness associated with the Company's cash flow hedges. There was no significant ineffectiveness recorded in 2001. Additionally, 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 SFAS No. 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 (New York Mercantile Exchange) 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, 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 will receive fixed prices ranging from $2.75 to $4.30 per MMBtu. Outstanding oil price swaps on 240 MBbls were in place that will yield 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 will pay 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 future 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. The Company's price risk management activities reduced revenues by $6.1 million in 2002, $10.3 million in 2001 and $39.3 million in 2000.

The Company has outstanding interest rate swaps on a notional amount of $40 million. Under these contracts the Company will make average fixed interest payments at 2.3% and receive variable prices based on the one-month LIBOR rate. The Company currently pays an additional 1.5% above LIBOR on its revolving credit facility.

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 Company's 1985 Nonqualified Stock Option Plan expired in 1992, except with respect to awards then outstanding. The following tables summarize stock option activity for the years 2002, 2001 and 2000 and provide information for options outstanding at December 31, 2002:

	2002		2001		2000	
	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	2,672,186	$ 9.84	2,602,800	$ 9.79	2,061,199	$ 10.49
Granted	346,010	11.43	170,200	10.13	666,100	7.58
Exercised	247,464	8.39	11,252	7.00	—	—
Canceled	60,914	10.09	89,562	9.22	124,499	9.55
Options outstanding at December 31	2,709,818	$ 10.17	2,672,186	$ 9.84	2,602,800	$ 9.79

	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	473,915	$ 6.16	6.5	458,248	$ 6.15
\$7.06 - \$8.75	721,759	7.41	7.4	532,396	7.40
\$8.76 - \$13.38	972,710	11.52	7.0	492,404	11.99
\$13.39 - \$17.50	541,434	14.94	2.4	509,653	14.97
	2,709,818	$ 10.17		1,992,701	$ 10.18

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 SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans.

The Company granted 233,460 shares, 299,850 shares and 149,925 shares of restricted stock in 2002, 2001 and 2000, respectively. The fair values of the grants were \$2.7 million for 2002, \$2.9 million for 2001 and \$1.1 million for 2000. Of the 986,475 shares granted to date, 433,715 shares vest over a three-year period, 510,210 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 \$1.3 million for 2002 and \$0.6 million for both 2001 and 2000. As of December 31, 2002, 441,331 shares have vested to employees and 47,021 shares have been canceled and returned to treasury shares.

(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, 2002 and 2001, the principal outstanding for these Notes was $71.0 million and $73.0 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. 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 expire in 2003 and are renewable year-to-year thereafter until terminated by 180 days' notice.

The Company leases certain office space and vehicles under non-cancelable operating leases expiring through 2006. 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, 2002, future minimum payments under non-cancelable leases accounted for as operating leases are $729,000 in 2003; $725,000 in 2004; $703,000 in 2005; and $496,000 in 2006. Total rent expense for all operating leases was $811,000, $706,000 and $815,000 in 2002, 2001 and 2000, respectively.

Additionally, the Company's utility segment has entered into various non-cancelable agreements related to demand charges for the transportation and purchase of natural gas with third parties. These costs are recoverable from the utility's end-use customers. At December 31, 2002, future payments under these non-cancelable demand contracts are $7,458,000 in 2003; $1,821,000 in 2004; $1,821,000 in 2005; $1,656,000 in 2006; $829,000 in 2007; and $3,727,000 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 SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information." The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production 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 "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
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(3)	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(3)	5,347	—	1,749	106,060
2000					
Revenues from external customers	$ 75,597	$151,052	$137,234	$ —	$363,883
Intersegment					
Intersegment revenues	35,323	182	70,514	448	106,467
Unusual items(4)	111,288	—	—	—	111,288
Operating income (loss)	(70,584)	14,655	2,460	—	(53,469)
Depreciation, depletion and amortization expense	39,048	6,625	109	87	45,869
Interest expense(1)	17,472	4,608	16	1,134	23,230
Provision (benefit) for income taxes(1)	(34,153)	4,869	912	(533)	(28,905)
Assets	460,296	188,811	20,929	35,342(2)	705,378
Capital expenditures	69,211	5,994	24	488	75,717

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

(4) Includes $109.3 million for the Hales judgment and $2.0 million for other litigation.

Intersegment sales by the exploration and production 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, 2002 and 2001:

	Mar 31	June 30	Sept 30	Dec 31
	(in thousands, except per share amounts)			
	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
	2001			
Operating revenues	$ 137,129	$ 76,023	$ 59,396	$ 72,379
Operating income	$ 32,599	$ 18,015	$ 14,263	$ 17,792
Net income	$ 16,013	$ 6,869	$ 5,018	$ 7,424
Basic earnings per share	$ 0.64	$ 0.27	$ 0.20	$ 0.29
Diluted earnings per share	$ 0.63	$ 0.27	$ 0.20	$ 0.29

(14) NEW ACCOUNTING STANDARDS

As previously disclosed, in July 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends FASB Statement No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 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. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. Accordingly, this standard will become applicable to the Company in the first quarter of 2003. The effect of this standard on the Company's results of operations and financial condition at adoption is expected to include an increase in current and long-term liabilities of $1.2 and $5.5 million, respectively; a net increase in property, plant and equipment of $5.4 million; a cumulative effect of adoption expense of $0.8 million and a deferred tax asset of $0.5 million. Subsequent to adoption, the Company does not expect this standard to have a material impact on the Company's financial position or its results of operations.

On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of FAS 123" (FAS 148). The standard provides additional transition guidance for companies that elect to voluntarily adopt the accounting provisions of FAS 123, "Accounting For Stock-Based Compensation." FAS 148 does not change the provisions of FAS 123 that permit entities to continue to apply the intrinsic value method of APB 25, "Accounting for Stock Issued to Employees" (APB 25). As the Company applies APB 25, its accounting for stock-based compensation will not change as a result of FAS 148. FAS 148 does require certain new disclosures in both annual and interim financial statements. The required annual disclosures were effective immediately for the Company and have been included in Note 1 of the Company's financial statements. The new interim disclosure provisions will be effective for the Company in the first calendar quarter of 2003.

On January 17, 2003, the FASB issued FASB Interpretation No. 46 ("FIN 46"), Consolidation of Variable Interest Entities, an interpretation of ARB 51. 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. The Company does not expect the adoption of this standard to have any impact on its 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 reports of Andersen on the consolidated financial statements of Southwestern and subsidiaries as of and for the fiscal years ended December 31, 2001 and December 31, 2000 did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty or audit scope. In addition, there were no modifications as to accounting principles except that the audit reports 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 our two most recent fiscal years ended December 31, 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 our two most recent fiscal years 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.

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 14, 2003, or the 2003 Proxy Statement, is hereby incorporated by reference for the purpose of providing information about the identification of our directors. We refer you to the sections "Election of Directors" and "Share Ownership of Management and Directors" in the 2003 Proxy Statement for information concerning our directors. Information concerning our executive officers is presented in Part I, Item 4 of this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The 2003 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 2003 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The 2003 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 and Directors" for information about security ownership of certain beneficial owners and our management.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The 2003 Proxy Statement is hereby incorporated by reference for the purpose of providing information about related transactions. Refer to the section "Share Ownership of Management and Directors" and "Equity Compensation Plans" for information about transactions with our executive officers, directors or management.

ITEM 14. CONTROLS AND PROCEDURES

Within 90 days before filing this Form 10-K, our Chief Executive Officer and our Chief Financial Officer evaluated the effectiveness of the design and operation of our disclosure controls and procedures. 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 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 accountants 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
January 24, 2003	7,9	No
December 4, 2002	7,9	No
November 20, 2002	5	No
November 14, 2002	7,9	No
November 12, 2002	7,9	No
October 30, 2002	7,9	No
October 25, 2002	7,9	No
October 18, 2002	7,9	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 14, 2003

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 14, 2003.

/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/ Kenneth R. Mourton Kenneth R. Mourton	Director
/s/ Charles E. Scharlau Charles E. Scharlau	Director

CERTIFICATION

I, Harold M. Korell, Chief Executive Officer of Southwestern Energy Company, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

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

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's independent accountants and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's independent accountants any material weaknesses in internal controls; and

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

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

Date: February 14, 2003

/s/ Harold M. Korell
Harold M. Korell
Chief Executive Officer

CERTIFICATION

I, Greg D. Kerley, Chief Financial Officer of Southwestern Energy Company, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

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

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's independent accountants and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's independent accountants any material weaknesses in internal controls; and

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

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

Date: February 14, 2003

/s/ Greg D. Kerley
Greg D. Kerley
Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
3.1*	Amended and Restated By-Laws of Southwestern Energy Company.
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)
10.1*	Consulting Agreement between Southwestern Energy Company and Charles E. Scharlau, dated May 15, 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.
10.12*	Southwestern Energy Company 2002 Performance Unit Plan, effective December 11, 2002.
10.13*	Purchase and Sale Agreement by and between Southwestern Energy Production Company, as Seller, and Dutch Petroleum, LLC, as Buyer, dated November 5, 2002 relating to the sale of the Mid-Continent properties.
21.1*	List of Subsidiaries
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of K&A Energy Consultants, Inc.

* Filed herewith

Annual Meeting

May 14, 2003 at
11:00 a.m. CDT
Wyndham Hotel –
Greenspoint
Houston, Texas

Independent Public Accountants

PricewaterhouseCoopers LLP
Tulsa, Oklahoma

Investor Relations

Greg D. Kerley
Executive Vice President and Chief Financial Officer

Brad D. Sylvester
Manager, Investor Relations
281-618-4897

Web Site
www.swn.com

Transfer Agent and Registrar

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02940-3069
800-446-2617

The DirectSERVICE Investment Program
c/o EquiServe
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Corporate Headquarters

Southwestern Energy Company
2350 N. Sam Houston Parkway East, Suite 300
Houston, Texas 77032
281-618-4700
281-618-4818 (fax)

Subsidiary Offices

Southwestern Energy Production Company
2350 N. Sam Houston Parkway East, Suite 300
Houston, Texas 77032
281-618-4700
281-618-4818 (fax)

SEECO, Inc.
1083 Sain Street
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Fayetteville, Arkansas 72703-1004
479-521-1141
479-521-0328 (fax)

Arkansas Western Gas Company
1001 Sain Street
P. O. Box 13288
Fayetteville, Arkansas 72703-1002
479-521-5400
479-582-4747 (fax)

Southwestern Energy Services Company
5314 S. Yale
Tulsa, Oklahoma 74135
918-584-4200
918-584-4222 (fax)

Forward-looking statements – This annual report contains forward-looking statements regarding Southwestern Energy Company's future plans and performance based on assumptions the Company believes are reasonable. A number of factors could cause actual results to differ materially from these statements. For further information regarding these factors, see Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's 2002 Form 10-K.

Southwestern Energy Company 2350 N. Sam Houston Parkway East, Suite 300, Houston, Texas 77032 281-618-4700