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

FORM 10-Q

(Mark one)

[X] Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **March 31, 2003**

or

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ________ to _________

Commission file number **1-8246**

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 N. Sam Houston Pkwy. E., Suite 300, Houston, Texas 77032
(Address of principal executive offices, including zip code)

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

Not Applicable
(Former name, former address and former fiscal year; if changed since last report)

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 twelve 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: X No: ___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes: X No: ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the lastest practicable date:

Class	Outstanding at April 15, 2003
Common Stock, Par Value $0.10	35,532,378

PART I

FINANCIAL INFORMATION

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended March 31, 2003	For the three months ended March 31, 2002
	(in thousands, except share/per share amounts)	
Operating Revenues:		
Gas sales	$ 77,707	$ 66,986
Gas marketing	12,606	9,702
Oil sales	3,459	3,183
Gas transportation and other	4,883	1,787
	98,655	81,658
Operating Costs and Expenses:		
Gas purchases - utility	27,048	24,768
Gas purchases - marketing	11,558	8,673
Operating expenses	9,046	9,558
General and administrative expenses	7,883	5,790
Depreciation, depletion and amortization	12,383	13,870
Taxes, other than income taxes	3,063	2,160
	70,981	64,819
Operating Income	27,674	16,839
Interest Expense:		
Interest on long-term debt	4,927	5,354
Other interest charges	385	322
Interest capitalized	(365)	(291)
	4,947	5,385
Other Income (Expense)	1,422	(242)
Income Before Income Taxes, Minority Interest & Accounting Change	24,149	11,212
Minority Interest in Partnership	(765)	(293)
Income Before Income Taxes & Accounting Change	23,384	10,919
Provision for Income Taxes - Deferred	8,887	4,204
Income Before Accounting Change	14,497	6,715
Cumulative Effect of Adoption of Accounting Principle	(855)	-
Net Income	$ 13,642	$ 6,715
Basic Earnings Per Share:		
Income Before Accounting Change	$0.51	$0.26
Cumulative Effect of Adoption of Accounting Principle	(0.03)	-
Net Income	$0.48	$0.26
Diluted Earnings Per Share:		
Income Before Accounting Change	$0.50	$0.26
Cumulative Effect of Adoption of Accounting Principle	(0.03)	-
Net Income	$0.47	$0.26
Weighted Average Common Shares Outstanding:		
Basic	28,138,469	25,499,294
Diluted	28,991,295	25,859,247

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

	March 31, 2003	December 31, 2002
	(in thousands)	
Current Assets		
Cash	$ 3,781	$ 1,690
Accounts receivable	52,639	42,115
Inventories, at average cost	16,331	24,735
Hedging asset - SFAS No. 133	419	3,130
Other	4,993	4,468
Total current assets	78,163	76,138
Investments	14,269	15,287
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method	1,059,025	1,030,300
Gas distribution systems	199,060	197,473
Gas in underground storage	28,005	32,395
Other	31,544	31,391
	1,317,634	1,291,559
Less: Accumulated depreciation, depletion and amortization	667,053	659,398
	650,581	632,161
Other Assets	16,700	16,576
Total Assets	$ 759,713	$ 740,162

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	March 31, 2003	December 31, 2002
	(in thousands)	
Current Liabilities		
Accounts payable	$ 31,451	$ 29,881
Taxes payable	4,114	5,213
Interest payable	6,239	2,513
Customer deposits	5,001	4,999
Hedging liability - SFAS No. 133	27,414	20,409
Regulatory liability - hedges	-	3,130
Over-recovered purchased gas costs	3,967	5,697
Other	4,546	2,715
Total current liabilities	82,732	74,557
Long-Term Debt	225,000	342,400
Other Liabilities		
Deferred income taxes	122,691	116,591
Other	24,181	16,671
	146,872	133,262
Commitments and Contingencies		
Minority Interest in Partnership	13,265	12,455
Shareholders' Equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 37,225,584 shares	3,723	2,774
Additional paid-in capital	121,392	19,130
Retained earnings	211,630	197,988
Accumulated other comprehensive income (loss)	(21,342)	(17,358)
	315,403	202,534
Less: Common stock in treasury, at cost, 1,693,206 shares at March 31, 2003 and 1,793,456 shares at December 31, 2002	18,864	19,981
Unamortized cost of 498,664 restricted shares at March 31, 2003 and 498,123 restricted shares at December 31, 2002 issued under stock incentive plan	4,695	5,065
	291,844	177,488
Total Liabilities and Shareholders' Equity	$ 759,713	$ 740,162

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the three months ended March 31, 2003	For the three months ended March 31, 2002
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 13,642	$ 6,715
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	13,105	14,472
Deferred income taxes	8,887	4,204
Ineffectiveness of cash flow hedges	914	-
Equity in (income) loss of NOARK partnership	(1,482)	200
Minority interest in partnership	765	293
Cumulative effect of adoption of accounting principle	855	-
Change in assets and liabilities:		
Accounts receivable	(10,523)	803
Inventories	8,404	2,059
Under/over-recovered purchased gas costs	(1,730)	-
Accounts payable	2,187	(12,241)
Taxes payable	(1,099)	94
Interest payable	3,726	3,951
Other operating assets and liabilities	921	802
Net cash provided by operating activities	38,572	21,352
Cash Flows From Investing Activities		
Capital expenditures	(30,369)	(21,369)
Distribution from NOARK partnership	2,500	-
Decrease in gas stored underground	4,391	4,047
Other items	749	944
Net cash used in investing activities	(22,729)	(16,378)
Cash Flows From Financing Activities		
Issuance of common stock	103,301	-
Payments on revolving long-term debt	(147,500)	(75,600)
Borrowings under revolving long-term debt	30,100	68,300
Change in bank drafts outstanding	(616)	-
Proceeds from exercise of common stock options	963	-
Net cash used in financing activities	(13,752)	(7,300)
Increase (decrease) in cash	2,091	(2,326)
Cash at beginning of year	1,690	3,641
Cash at end of period	$ 3,781	$ 1,315

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Common Stock		Additional Paid-In	Retained	Treasury	Unamortized Restricted Stock	Accumulated Other Comprehensive	
	Shares	Amount	Capital	Earnings	Stock	Awards	Income (Loss)	Total
				(in thousands)				
Balance at December 31, 2002	27,738	$ 2,774	$ 19,130	$ 197,988	$ (19,981)	$ (5,065)	$ (17,358)	$ 177,488
Comprehensive income:								
Net income	-	-	-	13,642	-	-	-	13,642
Change in value of derivatives	-	-	-	-	-	-	(3,984)	(3,984)
Total comprehensive income (loss)	-	-	-	-	-	-	-	9,658
Issuance of common stock	9,488	949	102,352	-	-	-	-	103,301
Exercise of stock options	-	-	(93)	-	1,056	-	-	963
Issuance of restricted stock	-	-	3	-	61	(64)	-	-
Amortization of restricted stock	-	-	-	-	-	434	-	434
Balance at March 31, 2003	37,226	$ 3,723	$ 121,392	$ 211,630	$ (18,864)	$ (4,695)	$ (21,342)	$ 291,844

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the three months ended March 31,	
	2003	2002
	(in thousands)	
Balance, beginning of period	$ (17,358)	$ 5,763
Current period reclassification to earnings	11,888	(1,776)
Current period change in derivative instruments	(15,872)	(11,812)
Balance, end of period	$ (21,342)	$ (7,825)

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
March 31, 2003 and 2002

(1) BASIS OF PRESENTATION

The financial statements included herein are unaudited; however, such information reflects all adjustments (consisting solely of normal recurring adjustments) which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. The Company's significant accounting policies are summarized in Note 1 in the Notes to Consolidated Financial Statements included in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2002 (the "2002 Annual Report on Form 10-K").

(2) ISSUANCE OF COMMON STOCK

In the first quarter of 2003, the Company completed the sale of 9,487,500 shares of its common stock under a registration statement filed with the Securities and Exchange Commission in December 2002. Aggregate net proceeds from the equity offering of approximately $103.3 million were used to pay outstanding borrowings under the credit facility. The Company will reborrow the repaid amounts under the credit facility as necessary to fund the acceleration of the development of the Company's Overton Field in East Texas and for general corporate purposes.

(3) 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 March 31, 2003, the Company's net book value of natural gas and oil properties did not exceed the ceiling amount. Decreases in market prices from March 31, 2003 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could result in future ceiling test impairments.

(4) 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 period. 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 851,234 shares of common stock with a weighted average exercise price of $14.15 per share at March 31, 2003, and options for 1,033,634 shares with an average exercise price of $13.68 per share at March 31, 2002, that were not included in the calculation of diluted shares because they would have had an antidilutive effect.

(5) LONG-TERM DEBT

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

	March 31, 2003	December 31, 2002
	(in thousands)	
Senior notes:		
6.70% Series due 2005	$ 125,000	$ 125,000
7.625% Series due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Series due 2017	40,000	40,000
	225,000	225,000
Other:		
Variable rate (2.89% at December 31, 2002) unsecured revolving credit arrangements	-	117,400
Total long-term debt	$ 225,000	$ 342,400

The Company's revolving credit facility has a capacity of $125 million and a three-year term that expires in July 2004. 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 65% of its total capital, must maintain a certain level of shareholders' equity, and the Company must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 4.00 or higher through December 31, 2003. These covenants change over the term of the credit facility and generally become more restrictive. Additionally, the Company is precluded from paying dividends on its common stock under the revolving credit agreement. At March 31, 2003, there were no borrowings under the revolving credit facility as the net proceeds from the issuance of common stock discussed above were used to reduce outstanding debt under the facility. The Company will reborrow the repaid amounts under the facility as necessary to fund the acceleration of the development drilling of the Overton Field in East Texas and for general corporate purposes. The Company has also entered into interest rate swaps for calendar year 2003 that allow the Company to pay a fixed interest rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of its outstanding revolving debt. As a result of the reduced level of current and anticipated borrowings under the revolving credit facility for the remainder of 2003, these interest rate swaps no longer qualify as cash flow hedges and therefore $0.2 million has been expensed in the accompanying financial statements.

(6) DERIVATIVE AND HEDGING ACTIVITIES

Statement of Financial Accounting Standards 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.

At March 31, 2003, the Company's net liability related to its cash flow hedges was $31.2 million. Additionally, at March 31, 2003, the Company had recorded a net of tax cumulative loss to other comprehensive income (equity section of the balance sheet) of $18.0 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the adoption of SFAS No. 133.

(7) 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
Three months ended March 31, 2003:					
Revenues from external customers	$ 28,609	$ 57,440	$ 12,606	$ --	$ 98,655
Intersegment revenues	11,127	67	35,314	112	46,620
Operating income	18,937	8,005	691	41	27,674
Depreciation, depletion and amortization expense	10,814	1,534	12	23	12,383
Interest expense [(1)]	3,723	981	--	243	4,947
Provision for income taxes [(1)]	5,496	2,640	263	488	8,887
Assets	545,682	155,166	18,320	40,545[(2)]	759,713
Capital expenditures	28,448	1,841	--	80	30,369

Three months ended March 31, 2002:					
Revenues from external customers	$ 23,564	$ 48,392	$ 9,702	$ --	$ 81,658
Intersegment revenues	4,856	65	16,921	112	21,954
Operating income	7,330	8,663	781	65	16,839
Depreciation, depletion and amortization expense	12,280	1,565	2	23	13,870
Interest expense (1)	4,253	904	--	228	5,385
Provision (benefit) for income taxes (1)	1,074	2,967	307	(144)	4,204
Assets	523,488	156,952	9,380	37,862(2)	727,682
Capital expenditures	19,881	1,348	--	140	21,369

(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 the NOARK Pipeline System, Limited Partnership, corporate assets not allocated to segments, and assets for non-reportable segments.

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.

(8) INTEREST AND INCOME TAXES PAID

The following table provides interest and income taxes paid during each period presented. Interest payments include amounts paid or received for the settlement of interest rate hedges.

	For the three months ended March 31,	
	2003	2002
	(in thousands)	
Interest payments	$ 968	$1,405
Income tax payments	$ --	$ --

(9) MINORITY INTEREST IN PARTNERSHIP

In 2001, the Company's subsidiary, Southwestern Energy Production Company (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 first 14 wells. Revenues and expenses are allocated 65% to SEPCO prior to payout of the investor's initial investment and 85% thereafter.

(10) 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. At March 31, 2003 and December 31, 2002, the principal outstanding for these notes was $71.0 million. The Company's share of the several guarantee is 60%. 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, 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 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.

(11) ASSET RETIREMENT OBLIGATIONS

Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) was adopted by the Company on January 1, 2003. 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. Associated with the adoption of the standard, the Company increased current and long-term liabilities by $1.2 million and $5.5 million, respectively, net property and equipment by $5.3 million, net deferred tax assets by $0.5 million, and recorded an expense of $0.9 million constituting the cumulative effect of adoption. The new standard had no material impact on income before the cumulative effect of adoption in the first quarter of 2003, nor would it have had a material impact in the first quarter of 2002 assuming an adoption of this accounting standard on a proforma basis.

(12) ACCOUNTING FOR STOCK-BASED COMPENSATION

The Company's stock-based employee compensation plan is accounted for 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 three months ended March 31,	
	2003	2003
	(in thousands, except per share)	
Net income, as reported	$ 13,642	$ 6,715
Add back: Amortization of restricted stock	434	313
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(715)	(567)
Pro forma net income	$ 13,361	$ 6,461
Earnings per share:		
Basic-as reported	$ 0.48	$ 0.26
Basic-pro forma	0.47	0.25
Diluted-as reported	0.47	0.26
Diluted-pro forma	0.46	0.25

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 for both quarters: no dividend yield; expected volatility of 45.6%; risk-free interest rate of 3.4%; and expected lives of 6 years for all option grants. There were no options granted in the first quarter of 2003. The fair value of the options granted in the first quarter of 2002 was $0.2 million.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following updates information as to the Company's financial condition provided in our 2002 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three month period ended March 31, 2003, and the comparable period of 2002. For definitions of commonly used gas and oil terms as used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2002 Annual Report on 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.

We reported net income of $13.6 million, or $0.47 per share on a fully diluted basis, on revenues of $98.7 million for the three months ended March 31, 2003, compared to $6.7 million, or $0.26 per share, on revenues of $81.7 million for the same period in 2002. The increase in earnings primarily resulted from higher natural gas prices experienced by our exploration and production segment, partially offset by a decrease in production volumes. The increase in revenues was primarily the result of higher natural gas and oil prices.

RESULTS OF OPERATIONS

Exploration and Production

Our exploration and production segment's revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, and there can be no assurance that gas and oil prices will not be subject to wide fluctuations in the future. Gas and oil prices affect the amount of cash flow available for capital expenditures, our ability to borrow and raise additional capital and the amount of gas and oil we can economically produce. We use hedging transactions with respect to a portion of our gas and oil production to achieve more predictable cash flows and to reduce our exposure to price fluctuations. Our future success depends on our ability to find, develop and acquire gas and oil reserves that are economically recoverable.

	For the Three Months Ended March 31,	
	2003	2002
Revenues (in thousands)	$39,736	$28,420
Operating income (in thousands)	$18,937	$ 7,330
Gas production (MMcf)	8,101	9,231
Oil production (MBbls)	125	183
Total production (MMcfe)	8,851	10,329
Average gas price per Mcf	$ 4.15	$ 2.76
Average oil price per Bbl	$27.69	$17.41
Average unit costs per Mcfe		
Lease operating expenses	$0.42	$0.43
General & administrative expenses	0.44	0.27
Taxes other than income taxes	0.27	0.15
Full cost pool amortization	1.18	1.16

Revenues, Operating Income and Production

Revenues. Revenues for our exploration and production segment were up 40% for the three-month period ended March 31, 2003 compared to the same period in 2002. The increase was due to higher gas and oil prices received for our production, partially offset by decreased production volumes.

Operating Income. Operating income for the exploration and production segment was up $11.6 million for the three months ended March 31, 2003, compared to the same period in 2002. The increase in operating income resulted from the increase in revenues.

Production. Gas and oil production during the first quarter of 2003 was 8.9 billion cubic feet (Bcf) equivalent, down from 10.3 Bcf equivalent in the first quarter of 2002. The comparative decrease in production resulted from declines experienced in our South Louisiana properties during the last half of 2002, combined with the loss of production resulting from the November 2002 sale of our Mid-Continent properties, partially offset by increased production from the Overton Field in East Texas. Gas production was 8.1 Bcf for the first three months of 2003, compared to 9.2 Bcf for the first quarter of 2002. We sold 1.7 Bcf to our gas distribution systems during the three months ended March 31, 2003, compared to 1.9 Bcf for the same period in 2002. Our oil production was 125 thousand barrels (MBbls) during the first quarter of 2003, down from 183 MBbls for the same period of 2002.

Commodity Prices

We received an average price of $4.15 per thousand cubic feet (Mcf) for our gas production for the three months ended March 31, 2003, up from $2.76 per Mcf for the same period of 2002. We hedged 7.3 Bcf of gas production in the first three months of 2003 through fixed-price swaps and zero-cost collars which had the effect of decreasing our average gas price realized during the period by $2.26 per Mcf. On a comparative basis, the average price realized during the first three months of 2002 included the effect of hedges that increased our average price by $0.44 per Mcf.

For the remainder of 2003, we have 13.6 Bcf of gas production hedged with collars having an average NYMEX floor price of $3.30 per Mcf and an average NYMEX ceiling price of $5.10 per Mcf. We also have 9.8 Bcf of gas production for the remainder of 2003 hedged with fixed-price swaps at an average NYMEX price of $3.47 per Mcf. For 2004, we have 25.2 Bcf hedged under zero-cost collars and fixed-price swaps. See Part I, Item 3 of this Form 10-Q for additional information regarding the Company's commodity price risk hedging activities.

We received an average price of $27.69 per barrel for our oil production during the three months ended March 31, 2003, up from $17.41 per barrel for the same period of 2002. The average price we received for our oil production in the first quarter of 2003 and 2002 was reduced by $4.37 per barrel and $1.48 per barrel, respectively, due to the effects of fixed-price swaps. For the remainder of 2003, we have a hedge on 270,000 barrels at an average NYMEX price of $26.73 per barrel.

Operating Costs and Expenses

Lease operating expenses per Mcfe for this business segment were $0.42 for the first quarter of 2003, compared to $0.43 for the same period in 2002. Taxes other than income taxes per Mcfe were $0.27 for the first three months of 2003, compared to $0.15 in the first three months of 2002. Severance taxes per Mcfe increased during the quarter due to higher average prices received for our production. The combined total operating costs and expenses for the exploration and production segment in the first three months of 2003 were approximately the same as in the prior year as higher general and administrative expenses and increased severance taxes were offset by lower lease operating expenses and lower depreciation, depletion and amortization expense. The increase in general and administrative expenses in 2003 resulted from increased pension, insurance and salary costs.

The Company utilizes the full cost method of accounting for costs related to its 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 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 gas and oil prices may subsequently increase the ceiling. Our full cost ceiling is evaluated at the end of each quarter. At March 31, 2003, our unamortized costs of gas and oil properties did not exceed this ceiling amount. A decline in gas and oil prices from current 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.

Natural Gas Distribution

The operating results of our gas distribution segment are highly seasonal. This segment typically realizes operating income during the winter heating season in the first and fourth quarters and operating losses in the second and third quarters of the year. The extent and duration of heating weather also impacts the profitability of this segment, although there is a weather normalization clause in our rates 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 Arkansas Public Service Commission (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.

	For the Three Months Ended March 31,	
	2003	2002
	(in thousands, except for Mcf amounts)	
Revenues	$57,507	$48,457
Gas purchases	$38,167	$29,618
Operating costs and expenses	$11,335	$10,176
Operating income	$8,005	$8,663
Deliveries (Bcf)		
Sales and end-use transportation	10.7	10.1
Off-system transportation	--	--
Average number of customers	140,549	138,071
Average sales rate per Mcf	$6.77	$5.98
Heating weather - degree days	2,275	2,049
Percent of normal	106%	95%

Revenues and Operating Income

Revenues. Gas distribution revenues fluctuate due to the pass-through of gas supply cost changes and the effects of weather. 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. Revenues for the three months ended March 31, 2003 increased 19% from the comparable period of 2002 due to the increase in volumes delivered and the increase in the cost of gas supplies caused by higher gas prices.

Operating Income. Operating income of our gas distribution segment decreased 8% in the first quarter of 2003, as compared to the same period of 2002. The decrease was primarily due to increased operating costs and expenses, partially offset by the sales margin from increased deliveries due to colder weather during the first quarter of 2003. Weather during the first quarter of 2003 was 6% colder than normal and 11% colder than the same period of 2002. The weather normalization clause in the utility's rates lessens the impacts of revenue increases and decreases that might result from weather variations during the winter heating season.

We 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, we expect any increase granted will become effective in September 2003. The APSC has set a hearing date for our application of July 22, 2003. Our last rate increase was approved in December 1996 for the utility's Northwest region and in December 1997 for the Northeast region.

Deliveries and Rates

The utility systems delivered 10.7 Bcf to sales and end-use transportation customers during the three months ended March 31, 2003, up from 10.1 Bcf for the same period in 2002. The increase in deliveries was primarily due to the effects of colder weather. The increase in gas costs in the first quarter of 2003 was reflected in the utility segment's average rate for its sales which increased to $6.77 per Mcf, up from $5.98 per Mcf for the same period in 2002. Costs paid for purchases of natural gas are passed through to customers under automatic adjustment clauses. Our utility segment hedged 2.7 Bcf of gas purchases in the first three months of 2003 decreasing the total gas supply cost by $7.5 million. In the first quarter of 2002, 3.3 Bcf of gas purchase hedges increased the total gas supply cost by $6.4 million.

Operating Costs and Expenses

The changes in purchased gas costs for our gas distribution segment reflect volumes purchased, prices paid for supplies and the mix of purchases from intercompany versus third-party sources. Other operating costs and expenses for this segment during the quarter ended March 31, 2003 were higher than the comparable period of the prior year due primarily to increased general and administrative expenses that resulted from increased pension, insurance and salary costs.

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 $0.7 million for the first quarter of 2003, compared to $0.8 million for the same period of 2002.

Marketing

	For the Three Months Ended March 31,	
	2003	2002
Marketing revenues (in thousands)	$47,920	$26,623
Marketing operating income (in thousands)	$691	$781
Gas volumes marketed (Bcf)	8.5	12.3

The increase in our gas marketing revenues for the quarter ended March 31, 2003 relates to a significant increase in natural gas commodity prices from the prior year and was offset by a comparable increase in purchased gas costs. Operating income for this segment was $0.7 million for the first three months of 2003, compared to $0.8 million for the same period in 2002. We marketed 8.5 Bcf of gas in the first three months of 2003, compared to 12.3 Bcf for the same period in 2002. The decrease in volumes marketed resulted from lower volumes marketed for third parties due to our continuing effort to reduce credit risk, and lower volumes marketed for our exploration and production subsidiaries due to changes in affiliated gas supply contracts.

Transportation

Our share of the NOARK Pipeline System Limited Partnership (NOARK) pretax results of operations included in other income was a gain of $1.5 million for the first quarter of 2003, compared to a loss of $0.2 million for the same period in 2002. The gain in the first quarter of 2003 resulted primarily from a gain of $1.3 million recognized by the Company on the sale of a 28-mile portion of NOARK's pipeline located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million and our share of the proceeds was $2.5 million.

Interest Expense

Interest expense decreased 8% for the first quarter of 2003, compared to the same period in 2002, due to lower average borrowings, a lower average interest rate, and increased capitalized interest. Interest is capitalized in the exploration and production segment on costs that are unevaluated and excluded from amortization.

Income Taxes

The effective tax rate for the three months ended March 31, 2003 was 38.0% compared to 38.5% for the same period in 2002. The changes in the provision for deferred income taxes recorded in the three months ended March 31, 2003, as compared to the same period in 2002, resulted primarily from the increase in the level of taxable income in 2003. Also impacting deferred taxes is 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.

Adoption of Accounting Principle

Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) was adopted by the Company on January 1, 2003. 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. The effect of this standard on the Company's results of operations and financial condition at adoption was an increase in current and long-term liabilities of $1.2 million and $5.5 million, respectively; a net increase in property, plant and equipment of $5.3 million; a cumulative effect of adoption expense of $0.9 million and a deferred tax asset of $0.5 million. 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.

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. During the first quarter of 2003, we completed the sale of 9,487,500 shares of our common stock under a registration statement filed with the Securities and Exchange Commission in December 2002. Aggregate net proceeds from the equity offering of $103.3 million were used to repay borrowings under our credit facility. We intend to reborrow the repaid amounts as necessary to fund the acceleration of the development of our Overton Field in East Texas and for general corporate purposes. As of March 31, 2003, there were no borrowings outstanding under the revolving credit facility as the proceeds from the issuance of common stock were initially used to reduce our revolving debt. We expect our capital expenditures (discussed below under "Capital Expenditures") for 2003 to be funded by the cash flow generated by our operations and the funds that may be available under our credit facility.

Net cash provided by operating activities was $38.6 million in the first quarter of 2003, compared to $21.4 million for the same period of 2002. The primary components of cash generated from operations are net income, depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. Historically, our capital expenditures have predominantly been funded through cash provided by operations. For the first three months of 2003 and 2002, cash provided by operating activities met or exceeded these requirements.

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 6 to the financial statements. Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon cash flow available.

Capital Expenditures

Our capital expenditures for the first three months of 2003 were $30.4 million, compared to $21.4 million for the same period in 2002. Capital investments during calendar year 2003 are currently expected to be approximately $158.6 million compared to $92.1 million in 2002. Our 2003 capital investment program is expected to be funded through cash flow from operations and our revolving credit facility. We may adjust our level of future capital investments dependent upon the level of cash flow generated from operations.

Off-Balance Sheet Arrangements

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 March 31, 2003, the outstanding principal amount of these notes was $71.0 million and our share of the guarantee was $42.6 million. 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 the first quarter of 2003 and do not expect to advance any funds during the remainder of 2003.

Our share of the results of operations included in other income related to our NOARK investment was a gain of $1.5 million for the first quarter of 2003, compared to a loss of $0.2 million for the same period in 2002. The gain in the first quarter of 2003 resulted primarily from NOARK's sale of a 28-mile portion of its pipeline located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million and our share of the proceeds was $2.5 million. In addition to the gain recognized on the sale, the improvements experienced recently in operating results of NOARK result primarily from the ability to collect higher transportation rates on interruptible volumes. We believe that we will be able to continue to reduce the losses we have experienced on the NOARK project and expect our investment in NOARK to be realized over the life of the system.

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 March 31, 2003 are as follows:

Contractual Obligations

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
			(in thousands)		
Long-term debt	$ 225,000	$ —	$ 125,000	$ —	$ 100,000
Operating leases(1)	6,638	1,156	2,250	1,200	2,033
Unconditional purchase obligations(2)	—	—	—	—	—
Demand charges(3)	15,900	6,502	3,643	2,236	3,519
Other long-term obligations(4)	3,060	3,060	—	—	—
	$ 250,598	$ 10,718	$ 130,893	$ 3,436	$ 105,552

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

(2) Our utility segment has volumetric commitments for the purchase of gas under competitive bid packages and wellhead contracts. Volumetric purchase commitments at March 31, 2003 totaled 2.8 Bcf, comprised of 1.2 Bcf in less than one year, 0.9 Bcf in one to three years, 0.5 Bcf in three to five years and 0.2 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 $1.5 million for drilling rig commitments and approximately $0.8 million of various information technology support and data subscription agreements.

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

Contingent Liabilities 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, will result in an increase in pension expense and our required funding of the plans for 2003. As a result of recently completed actuarial data, we expect to record pension expense of approximately $3.4 million in 2003, of which $0.8 million has been recorded in the first quarter.

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 March 31, 2003 the principal outstanding for these notes was $71.0 million. The notes require semi-annual principal payments of $1.0 million.

Financing Requirements

Our total debt outstanding was $225.0 million at March 31, 2003 and $342.4 million at December 31, 2002. In July 2001, we arranged an unsecured revolving credit facility with a group of banks to replace a short-term credit facility that was put in place in July 2000. The revolving credit facility has a current capacity of $125 million and expires in July 2004. The interest rate on the current facility is 150 basis points over the current LIBOR. The credit facility contains covenants which impose certain restrictions on us. Under the credit agreement, we may not issue total debt in excess of 65% of our total capital, we must maintain a certain level of shareholders' equity, and we must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 4.00 or higher through December 31, 2003. These covenants change over the term of the credit facility and generally become more restrictive. Additionally, we are precluded from paying dividends on our common stock under the revolving credit agreement. At March 31, 2003, there were no borrowings under the revolving credit facility as proceeds from the issuance of common stock discussed above were initially used to reduce revolving debt. We have also entered into interest rate swaps for calendar year 2003 that allow us to pay a fixed interest rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of our outstanding revolving debt. As a result of the reduced level of current and anticipated borrowings under the revolving credit facility for the remainder of 2003, these interest rate swaps no longer qualify as cash flow hedges and therefore $0.2 million has been expensed in the accompanying financial statements.

During the first three months of 2003, our total debt decreased by $117.4 million primarily due to the initial use of the net proceeds from the issuance of common stock to pay off the balance of our revolving debt. We intend to reborrow the repaid amounts as necessary to fund the acceleration of the development drilling of our Overton Field properties in East Texas and for general corporate purposes as these costs are incurred. Total debt at March 31, 2003, accounted for 44% of our total capitalization. Our total debt is expected to increase during the remainder of 2003 as capital expenditures are anticipated to exceed cash flow from operations. However, we expect our debt as a percentage of our total capitalization to remain at approximately the same level as the equity in our balance sheet increases with our earnings.

At March 31, 2003, the NOARK partnership had outstanding debt totaling $71.0 million. We and 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%.

Working Capital

We maintain access to funds that may be needed to meet seasonal requirements through our credit facility described above. We had negative working capital of $4.6 million at March 31, 2003, compared to positive working capital of $1.6 million at December 31, 2002. Current assets increased by 3% in the first quarter of 2003 and current liabilities increased 11%. The net increase in current assets during the first quarter was due primarily to a $10.5 million increase in accounts receivable caused by higher natural gas prices in March 2003, offset by a $8.5 million decrease in gas stored in inventory due to withdrawals to meet sales requirements. The primary reason for the increase in current liabilities was a $7.0 million increase in our hedging liability recorded under the provisions of SFAS No. 133. At March 31, 2003, we had a current hedging asset of $0.4 million and a current hedging liability of $27.4 million recorded as a result of the provisions of SFAS No. 133. Changes in accounts payable, interest payable and other current assets and liabilities since December 31, 2002 are due primarily to the timing of expenditures and receipts. Over-recovered purchased gas costs for the Company's gas distribution segment were $4.0 million at March 31, 2003, compared to $5.7 million at December 31, 2002. Purchased gas costs are recovered from our utility customers in subsequent months through automatic cost of gas adjustment clauses included in the utility's filed rate tariffs.

CRITICAL ACCOUNTING POLICIES

Natural Gas and Oil Properties

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

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Application of these rules during periods of relatively low natural gas or oil prices, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on March 31, 2003, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

Natural gas and oil reserves used in the full cost method of accounting cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and is generally less precise than other estimates made in connection with financial disclosures. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We engage the services of an independent petroleum consulting firm to review reserves as 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, as well as to manage the price volatility of natural gas purchases in our gas distribution segment, 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-Q 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. 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 was 6.8% and the expected return assumed was 9.0%.

Using the assumed rates discussed above, we recorded pension expense of $0.9 million in 2002 and a pension liability of $5.6 million at December 31, 2002. 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.

For 2003, we expect our pension expense to be approximately $3.4 million using an assumed discount rate of 6.8% and an assumed expected return of 9.0%. Accordingly, pension expense of $.8 million was recorded in the first quarter of 2003.

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 8.1 Bcf at $2.92 at March 31, 2003 and 10.1 Bcf at $3.05 at December 31, 2002.

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.

FORWARD-LOOKING INFORMATION

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

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q 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 set forth in our 2002 Annual Report on Form 10-K which are incorporated by reference herein.

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 incorporated by reference 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.

PART I

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES 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. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. 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 7% of accounts receivable. See the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

Revolving debt obligations are sensitive to changes in interest rates. 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 calendar year 2003 that allow us to pay an average fixed 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 debt was $117.4 million at December 31, 2002, and had an average interest rate of 3.23%. At March 31, 2003, we had no outstanding revolving debt. As a result of the reduced level of current and anticipated borrowings under the revolving credit facility for the remainder of 2003, these interest rate swaps no longer qualify as cash flow hedges and therefore $0.2 million has been expensed in the accompanying financial statements.

Our interest rate swaps have a carrying amount of $0.7 million, 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 $0.3 million represents the value for the same contracts using comparable market prices at March 31, 2003. At March 31, 2003, the “Carrying Amount” exceeded the “Fair Value” of interest rate swaps by $0.4 million.

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 (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 we pay to (production hedge) or receive from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

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

The following table provides information about our financial instruments that are sensitive to changes in commodity prices. The table presents the notional amount in Bcf (billion cubic feet) and MBbls (thousand barrels), 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 March 31, 2003. At March 31, 2003, the "Carrying Amount" exceeded the "Fair Value" of these financial instruments by $30.8 million.

	Expected Maturity Date			
	2003		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Natural Gas:				
Swaps with a fixed price receipt				
Contract volume (Bcf)	9.8		7.2	
Weighted average price per Mcf	$3.47		$4.01	
Contract amount (in millions)	$34.0	$17.7	$28.9	$24.4
Swaps with a fixed price payment				
Contract volume (Bcf)	0.1		-	
Weighted average price per Mcf	$6.02		-	
Contract amount (in millions)	$0.5	$0.4	-	-
Price collar				
Contract volume (Bcf)	13.6		18.0	
Weighted average floor price per Mcf	$3.30		$3.78	
Contract amount of floor (in millions)	$44.8	$41.7	$68.0	$70.4
Weighted average ceiling price per Mcf	$5.10		$5.77	
Contract amount of ceiling (in millions)	$69.1	$65.4	$103.8	$98.6
Oil:				
Swaps with a fixed price receipt				
Contract volume (MBbls)	270		-	
Weighted average price per Bbl	$26.73		-	
Contract amount (in millions)	$7.2	$6.9	-	-

ITEM 4. CONTROLS AND PROCEDURES

Within the 90 days prior to the date of this report, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of our evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the disclosure controls and procedures are effective in all material respects to ensure that information required to be disclosed in the reports we file and submit under the Exchange Act is recorded, processed, summarized and reported as and when required.

PART II

OTHER INFORMATION

Items 1 - 5.

No developments required to be reported under Items 1 - 5 occurred during the quarter ended March 31, 2003.

Item 6(a). Exhibits

(99.1) Certification of CEO and CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Item 6(b). Reports on Form 8-K

Date of Report	Item Number	Financial Statements Required to be Filed
March 20, 2003	5	No
March 12, 2003	7,9	No
March 7, 2003	5	No
March 5, 2003	7,9	No
February 28, 2003	5	No
February 18, 2003	7,9	No
February 18, 2003	5	No
February 18, 2003	7,9	No
February 18, 2003	5,7,9	No

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
Registrant

DATE: April 24, 2003

/s/ GREG D. KERLEY
Greg D. Kerley
Executive Vice President
and Chief Financial Officer

CERTIFICATION

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

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

2. Based on my knowledge, this quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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 quarterly 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 quarterly report (the "Evaluation Date"); and

    (c) presented in this quarterly 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 auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

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

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

6. The registrant's other certifying officers and I have indicated in this quarterly 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: April 24, 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 quarterly report on Form 10-Q of Southwestern Energy Company;

2. Based on my knowledge, this quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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 quarterly 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 quarterly report (the "Evaluation Date"); and

(c) presented in this quarterly 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 auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

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

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

6. The registrant's other certifying officers and I have indicated in this quarterly 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: April 24, 2003

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

Exhibit 99.1

CERTIFICATION
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of Southwestern Energy Company, an Arkansas corporation (the "Company"), does hereby certify that:

> The Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (the "Form 10-Q") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: April 24, 2003

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

Dated: April 24, 2003

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

A signed original of this written statement required by section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished solely pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code) and is not being filed as part of the Form 10-Q or as a separate disclosure document.