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 **June 30, 2002**

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 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)

No Change
(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 the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	Outstanding at August 9, 2002
Common Stock, Par Value $.10	25,722,083

PART I

FINANCIAL INFORMATION

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

	June 30, 2002	December 31, 2001
	($ in thousands)	
Current Assets		
Cash	$ 2,789	$ 3,641
Accounts receivable	28,787	42,763
Inventories, at average cost	25,434	26,606
Hedging asset - SFAS No. 133	4,285	9,381
Regulatory asset - hedges	-	5,817
Other	3,925	4,996
Total current assets	65,220	93,204
Investments	15,177	15,538
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method	1,008,402	970,680
Gas distribution systems	194,800	192,784
Gas in underground storage	30,807	32,046
Other	30,547	30,110
	1,264,556	1,225,620
Less: Accumulated depreciation, depletion and amortization	633,335	605,790
	631,221	619,830
Other Assets	13,359	14,551
Total Assets	$ 724,977	$ 743,123

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	June 30, 2002	December 31, 2001
	($ in thousands)	
Current Liabilities		
Accounts payable	27,448	41,644
Taxes payable	2,806	4,400
Interest payable	2,414	2,653
Customer deposits	4,699	4,845
Hedging liability - SFAS No. 133	10,300	6,990
Over-recovered purchased gas costs	6,732	8,184
Other	4,182	2,752
Total current liabilities	58,581	71,468
Long-Term Debt	344,500	350,000
Other Liabilities		
Deferred income taxes	119,719	122,381
Other	7,721	3,187
	127,440	125,568
Commitments and Contingencies		
Minority Interest in Partnership	13,161	13,001
Shareholders' Equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 27,738,084 shares	2,774	2,774
Additional paid-in capital	19,433	19,764
Retained earnings	192,162	183,677
Accumulated other comprehensive income (loss)	(6,354)	5,763
	208,015	211,978
Less: Common stock in treasury, at cost, 2,054,972 shares in 2002 and 2,261,766 shares in 2001	23,571	25,196
Unamortized cost of 420,562 restricted shares in 2002 and 416,537 restricted shares in 2001 issued under stock incentive plans	3,149	3,696
	181,295	183,086
Total Liabilities and Shareholders' Equity	$ 724,977	$ 743,123

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

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

	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
	($ in thousands, except per share amounts)			
Operating Revenues				
Gas sales	$ 37,606	$ 52,173	$ 104,592	$ 147,558
Gas marketing	12,228	17,523	21,930	52,712
Oil sales	4,416	4,682	7,599	8,844
Gas transportation and other	1,754	1,645	3,541	4,038
	56,004	76,023	137,662	213,152
Operating Costs and Expenses				
Gas purchases - utility	3,804	9,370	28,572	50,498
Gas purchases - marketing	11,454	16,845	20,127	50,580
Operating expenses	9,505	9,215	19,063	19,678
General and administrative expenses	6,034	7,580	11,824	12,407
Depreciation, depletion and amortization	13,868	12,637	27,738	24,274
Taxes, other than income taxes	2,439	2,361	4,599	5,101
	47,104	58,008	111,923	162,538
Operating Income	8,900	18,015	25,739	50,614
Interest Expense				
Interest on long-term debt	5,345	5,904	10,699	12,771
Other interest charges	336	538	658	829
Interest capitalized	(360)	(424)	(651)	(860)
	5,321	6,018	10,706	12,740
Other Income (Expense)	(232)	(358)	(474)	22
Income Before Income Taxes & Minority Interest	3,347	11,639	14,559	37,896
Minority Interest in Partnership	(469)	(384)	(762)	(384)
Income Before Income Taxes	2,878	11,255	13,797	37,512
Income Tax Provision				
Current	-	-	-	-
Deferred	1,108	4,386	5,312	14,630
	1,108	4,386	5,312	14,630
Net Income	$ 1,770	$ 6,869	$ 8,485	$ 22,882
Basic Earnings Per Share	$0.07	$0.27	$0.34	$0.91
Basic Average Common Shares Outstanding	25,208,974	25,189,623	25,146,550	25,188,370
Diluted Earnings Per Share	$0.07	$0.27	$0.33	$0.89
Diluted Average Common Shares Outstanding	26,131,452	25,657,842	25,995,692	25,576,721

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

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

	Six Months Ended June 30,	
	2002	2001
	($ in thousands)	
Cash Flows From Operating Activities		
Net income	$ 8,485	$ 22,882
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	28,939	25,017
Deferred income taxes	5,312	14,630
Equity in loss of NOARK partnership	361	789
Minority interest in partnership	160	384
Change in assets and liabilities:		
Accounts receivable	13,976	39,099
Inventories	1,172	(7,127)
Under/over-recovered purchased gas costs	(1,452)	8,311
Accounts payable	(14,196)	(19,419)
Taxes payable	(1,594)	(1,426)
Other current assets and liabilities	1,093	1,248
Net cash provided by operating activities	42,256	84,388
Cash Flows From Investing Activities		
Capital expenditures	(40,774)	(47,990)
Investment in NOARK partnership	-	(1,449)
Change in gas stored underground	1,239	(2,236)
Other items	1,927	1,493
Net cash used in investing activities	(37,608)	(50,182)
Cash Flows From Financing Activities		
Net change in revolving long-term debt	(5,500)	(39,000)
Contributions from minority interest partner	-	3,900
Net cash used in financing activities	(5,500)	(35,100)
Decrease in cash	(852)	(894)
Cash at beginning of year	3,641	2,386
Cash at end of period	$ 2,789	$ 1,492

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2001*	2002	2001*
	($ in thousands)		($ in thousands)	
Net income	$ 1,770	$ 6,869	$ 8,485	$ 22,882
Other comprehensive income (loss):				
Transition adjustment from adoption of SFAS No. 133	-	-	-	(36,963)
Change in value of derivative instruments	1,471	16,774	(12,117)	41,564
Comprehensive Income (Loss)	$ 3,241	$ 23,643	$ (3,632)	$ 27,483

Reconciliation of Accumulated Other Comprehensive Income (Loss):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2001*	2002	2001*
Balance, Beginning of Period	$ (7,825)	$ (12,173)	$ 5,763	$ -
Cumulative effect of adoption of SFAS No. 133	-	-	-	(36,963)
Current period reclassification to earnings	2,432	1,832	656	22,378
Current period change in derivative instruments	(961)	14,942	(12,773)	19,186
Balance, End of Period	$ (6,354)	$ 4,601	$ (6,354)	$ 4,601

* The 2001 Consolidated Statements of Comprehensive Income (Loss) were restated to correct the presentation of comprehensive income, as discussed in Footnote 1 in Notes to Consolidated Financial Statements.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

JUNE 30, 2002

1. BASIS OF PRESENTATION

The financial statements included herein are unaudited; however, such financial statements reflect 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 accounting policies are summarized in the 2001 Annual Report on Form 10-K, Item 8, Notes to Consolidated Financial Statements.

In the second quarter of 2002, the Company corrected its presentation of comprehensive income for prior quarters to properly reflect amounts associated with hedging activities. This change resulted in a decrease of $1.8 million to previously reported comprehensive income for the three months ended March 31, 2002 and an increase of $22.4 million for the six months ended June 30, 2001. The Company determined this correction in the presentation of comprehensive income is also warranted for the year ended December 31, 2001, increasing the amount previously reported by $22.9 million to yield corrected comprehensive income of $41.1 million. These corrections had no effect on the Company's previously reported net income, earnings per share or cash flows, nor did it have any impact on the Company's balance sheet. These corrections in the presentation of comprehensive income will be reflected in amendments to the Company's filings on Form 10-K and Form 10-Q that will be completed in the third quarter of 2002 in conjunction with the Company's change in auditors from Arthur Andersen LLP to PricewaterhouseCoopers LLP.

2. OIL AND GAS PROPERTIES

The Company utilizes the full cost method of accounting for costs related to its oil and natural gas 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 oil and gas prices may subsequently increase the ceiling. At June 30, 2002, the Company's unamortized costs of oil and gas properties did not exceed this ceiling amount. The Company's full cost ceiling is evaluated at the end of each quarter. 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.

3. **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 average number of common shares outstanding is reduced for shares of restricted stock granted under the Company's incentive compensation plans that have not yet vested. 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 incremental shares of restricted stock assuming full vesting. The Company had options for 538,934 shares of common stock with a weighted average exercise price of $14.95 per share at June 30, 2002, and options for 896,015 shares with an average exercise price of $14.08 per share at June 30, 2001, that were not included in the calculation of diluted shares because they would have had an antidilutive effect.

4. **LONG-TERM DEBT**

In July 2001, the Company arranged an unsecured revolving credit facility with a group of banks that has a current capacity of $140 million and a three-year term. The interest rate on the current facility was 137.5 basis points over the current London Interbank Offered Rate (LIBOR), and was 4.6%, including the effects of interest rate swaps, at June 30, 2002. In July 2002, the interest rate increased to 150 basis points over LIBOR as the result of a downgrade of the Company's public debt by Moody's. 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 the Company 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. At June 30, 2002, the Company's revolving credit facility had a balance of $119.5 million and was classified as long-term debt in the Company's balance sheet. The Company has also entered into interest rate swaps for calendar year 2002 that allow the Company to pay a fixed interest rate of 4.9% (based upon current rates under the revolving credit facility) on $100.0 million of its outstanding revolving debt.

5. **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 June 30, 2002, the Company's net liability related to its cash flow hedges was $10.2 million. Additionally, at June 30, 2002, the Company had recorded a net of tax cumulative loss to other comprehensive income (equity section of the balance sheet) of $6.4 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.

6. 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 are shown in the following table. The "Other" column includes items related to non-reportable segments (real estate and pipeline operations) and corporate items.

	Exploration and Production	Gas Distribution	Marketing	Other	Total
			($ in thousands)		
Three months ended June 30, 2002:					
Revenues from external customers	$ 26,915	$ 16,860	$ 12,229	$ --	$ 56,004
Intersegment revenues	4,501	23	25,784	112	30,420
Operating income (loss)	10,063	(1,718)	503	52	8,900
Depreciation, depletion and amortization expense	12,248	1,564	32	24	13,868
Interest expense[(1)]	4,473	637	--	211	5,321
Provision (benefit) for income taxes[(1)]	1,980	(945)	196	(123)	1,108
Assets	539,565	144,681	12,595	28,136[(2)]	724,977[(2)]
Capital expenditures	17,954	1,412	2	37	19,405
Three months ended June 30, 2001:					
Revenues from external customers	$ 38,914	$ 19,586	$ 17,523	$ --	$ 76,023
Intersegment revenues	1,797	20	37,105	112	39,034
Operating income (loss)	18,272	(768)	444	67	18,015
Depreciation, depletion and amortization expense	11,039	1,557	16	25	12,637
Interest expense[(1)]	5,255	380	128	255	6,018
Provision (benefit) for income taxes[(1)]	4,921	(403)	123	(255)	4,386
Assets	498,862	151,300	13,415	32,238[(2)]	695,815[(2)]
Capital expenditures	31,334[(3)]	1,260	17	65	32,676[(3)]

Six months ended June 30, 2002:					
Revenues from external customers	$ 50,479	$ 65,252	$ 21,931	$ --	$ 137,662
Intersegment revenues	9,357	88	42,705	224	52,374
Operating income	17,393	6,945	1,284	117	25,739
Depreciation, depletion and amortization expense	24,528	3,129	34	47	27,738
Interest expense(1)	8,726	1,541	--	439	10,706
Provision (benefit) for income taxes(1)	3,054	2,022	503	(267)	5,312
Assets	539,565	144,681	12,595	28,136(2)	724,977(2)
Capital expenditures	37,835	2,760	2	177	40,774
Six months ended June 30, 2001:					
Revenues from external customers	$ 59,491	$ 100,949	$ 52,712	$ --	$ 213,152
Intersegment revenues	21,960	149	72,948	224	95,281
Operating income	40,260	8,630	1,587	137	50,614
Depreciation, depletion and amortization expense	21,085	3,108	33	48	24,274
Interest expense(1)	10,577	1,471	162	530	12,740
Provision (benefit) for income taxes(1)	11,422	3,000	556	(348)	14,630
Assets	498,862	151,300	13,415	32,238(2)	695,815(2)
Capital expenditures	45,633(3)	2,169	17	171	47,990(3)

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

(2) Other assets includes 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.

(3) Capital expenditures for the Exploration and Production segment include $7.8 million for the three and six month periods ended June 30, 2001, related to the consolidated results of a limited partnership. The Company received reimbursement of $3.9 million of these amounts from the minority interest partner.

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, prepaid pension costs and other prepaid expenses. 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.

7. INTEREST AND INCOME TAXES PAID

The following table provides interest and income taxes paid during each period presented.

Six Months Ended June 30	2002	2001
	(in thousands)	
Interest payments	$ 10,973	$13,232
Income tax payments	$ --	$ --

8. MINORITY INTEREST IN PARTNERSHIP

In the second quarter of 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 the first 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.

9. 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 June 30, 2002 and December 31, 2001, the principal outstanding for these Notes was $72.0 million and $73.0 million, respectively. 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 at various dates through July 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 noncapital 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 other 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.

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 the Company's Form 10-K for the year ended December 31, 2001, and analyzes the changes in the results of operations between the three and six month periods ended June 30, 2002, and the comparable periods of 2001.

RESULTS OF OPERATIONS

Net income for the three months ended June 30, 2002 was $1.8 million, or $.07 per share, compared to $6.9 million, or $.27 per share, for the same period in 2001. Net income for the six months ended June 30, 2002 was $8.5 million, or $.33 per share, compared to $22.9, or $.89 per share, for the six months ended June 30, 2001. The decreases in earnings resulted primarily from lower natural gas prices experienced by the Company's exploration and production segment, partially offset by an increase in natural gas production.

Exploration and Production

Overview

The Company's 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 its 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 oil and gas prices will not be subject to wide fluctuations in the future.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Revenues (in thousands)	$31,416	$40,711	$59,836	$81,451
Operating income (in thousands)	$10,063	$18,272	$17,393	$40,260
Gas production (MMcf)	9,128	8,653	18,359	16,678
Oil production (MBbls)	195	191	378	352
Total production (MMcfe)	10,298	9,799	20,627	18,790
Average gas price per Mcf	$2.96	$4.16	$2.86	$4.31
Average oil price per Bbl	$22.62	$24.59	$20.10	$25.15

Operating expenses per Mcfe				
Production expenses	$0.42	$0.44	$0.43	$0.48
Production taxes	$0.18	$0.18	$0.16	$0.20
General & administrative expenses	$0.28	$0.54(1)	$0.28	$0.39(1)
Full cost pool amortization	$1.16	$1.10	$1.16	$1.09

(1) Includes $2.0 million, or $.20 per Mcfe for the three months ended June 30, 2001 and $.11 per Mcfe for the six months ended June 30, 2001, for settled litigation.

Revenues and Operating Income

Revenues for the exploration and production segment were down 23% for the three month period and down 27% for the six month period ended June 30, 2002, both as compared to the same periods in 2001. The decreases were due to lower gas and oil prices received in 2002, partially offset by increased gas and oil production in 2002.

Operating income for the exploration and production segment was down $8.2 million for the three months ended June 30, 2002, and down $22.9 million for the first six months of 2002, both as compared to the same periods in 2001. The decreases in operating income were primarily due to lower segment revenues.

Production

Gas and oil production during the second quarter of 2002 was 10.3 billion cubic feet (Bcf) equivalent, up 5% from 9.8 Bcf equivalent for the same period in 2001. The increase in production resulted from the Company's continued development of its South Louisiana properties and its Overton Field in East Texas. Gas production was 9.1 Bcf for the second quarter of 2002, compared to 8.7 Bcf for the same period in 2001. For the six months ended June 30, 2002, gas and oil production was 20.6 Bcf equivalent compared to 18.8 Bcf equivalent for the same period in 2001. Gas production was 18.4 Bcf for the first six months of 2002 compared to 16.7 in 2001. The Company's sales to its gas distribution systems were 3.2 Bcf during the six months ended June 30, 2002, compared to 3.1 Bcf for the same period in 2001. The Company's oil production was 378 thousand barrels (MBbls) during the first six months of 2002, up from 352 MBbls for the same period of 2001.

Commodity Prices

The Company realized an average price of $2.96 per thousand cubic feet (Mcf) for its natural gas production for the three months ended June 30, 2002, down 29% from $4.16 per Mcf for the same period of 2001. The Company hedged 13.5 Bcf of gas production in the first six months of 2002 through fixed-price swaps and zero-cost collars, which had the effect of reducing the average gas price realized by $.37 per Mcf in the second quarter of 2002 and increasing the average gas price realized by $.04 per Mcf during the first half of 2002. On a comparative basis, the average realized price during the second quarter of 2001 was reduced by $.49 per Mcf and by $1.57 per Mcf in the first half of 2001, due to the effect of commodity price hedges.

For the remainder of 2002, the Company has 7.4 Bcf of gas production hedged with collars having an average NYMEX floor price of $3.29 per Mcf and an average NYMEX ceiling price of $4.30 per

Mcf. The Company also has 7.4 Bcf of gas production for the remainder of 2002 hedged with fixed price swaps at an average NYMEX price of $3.03 per Mcf. For the years 2003 and 2004 combined, the Company has 36.3 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.

The Company received an average price of $20.10 per barrel for its oil production during the six months ended June 30, 2002, down from $25.15 per barrel for the same period of 2001. The Company's hedging activities lowered the average realized oil price by $1.96 per barrel for the first half of 2002, and by $1.11 per barrel for the first half of 2001. For the remainder of 2002, the Company has a hedge on 166,500 barrels at an average NYMEX price of $20.07 per barrel.

Operating Costs and Expenses

Total operating costs and expenses for the exploration and production segment decreased 5% in the second quarter of 2002, as compared to the same period in 2001, as a result of lower general and administrative expenses, partially offset by higher depreciation, depletion and amortization expense. The comparative decrease in general and administrative expenses in 2002 resulted primarily from costs incurred to settle litigation during 2001. Total operating costs and expenses for the first six months of 2002 were up 3% compared to the prior year due to increased depreciation, depletion and amortization expense, partially offset by lower general and administrative expenses. The increases in depreciation, depletion and amortization expense were due to the increase in production and an increase in the amortization rate per unit of production. The full cost pool amortization rate for this segment averaged $1.16 per Mcf equivalent for the first six months of 2002, compared to $1.09 per Mcf equivalent in the first six months of 2001.

Gas Distribution

Overview

The operating results of the Company's gas distribution segment are highly seasonal. This segment typically realizes operating losses in the second and third quarters of the year and realizes operating income during the winter heating season in the first and fourth quarters. The extent and duration of heating weather also impacts the profitability of this segment, although the Company has 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 Arkansas Public Service Commission. For periods subsequent to allowed rate increases, the Company's profitability is impacted by its ability to manage and control this segment's operating costs and expenses.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	($ in thousands, except for per Mcf amounts)			
Revenues	$16,883	$19,606	$65,340	$101,098
Gas purchases	$8,300	$11,148	$37,918	$72,437
Operating costs and expenses	$10,301	$9,226	$20,477	$20,031
Operating income (loss)	$(1,718)	$(768)	$6,945	$8,630
Deliveries (Bcf)				
Sales and end-use transportation	3.9	3.6	14.0	14.1
Off-system transportation	.7	1.0	.7	1.0
Average number of customers	136,488	133,733	137,280	135,177
Average sales rate per Mcf	$7.66	$9.39	$6.32	$9.33
Heating weather - degree days	228	166	2,277	2,327
- percent of normal	74%	55%	92%	95%

Revenues and Operating Income

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 and six month periods ended June 30, 2002 are down from the comparable periods of 2001 primarily due to the significant drop in the cost of the utility's gas supply from the record high levels experienced during the first half of 2001. The decrease in the cost of gas supply is reflected in the Company's average rate for its utility sales which decreased during the first six months of 2002 to $6.32 per Mcf, down from $9.33 per Mcf for the same period in 2001. Costs paid for purchases of natural gas are passed through to the utility's customers under automatic adjustment clauses.

Operating income of the gas distribution segment decreased 124% in the second quarter of 2002 and decreased 20% in the first six months of 2002, as compared to the same periods of 2001. The decrease in operating income for the second quarter of 2002 was due to increased operating costs. Operating costs in the second quarter of 2001 were comparatively decreased as a result of a favorable settlement of open issues with the Missouri Public Service Commission. Operating income of the Company's gas distribution segment for the six months ended June 30, 2002 was lower, as compared to 2001, due to increased operating costs and warmer weather. Weather for the first six months of 2002 was 8% warmer than normal and 2% warmer than the same period of the prior year. The weather normalization clause in the Company's rates lessens the impacts of revenue increases and decreases that result from weather variations during the winter heating season.

Deliveries
The utility systems delivered 14.0 Bcf to sales and end-use transportation customers during the six months ended June 30, 2002, down from 14.1 Bcf for the same period in 2001. The decrease in deliveries was primarily due to the effects of warmer weather.

Operating Costs and Expenses
The changes in purchased gas costs for the gas distribution segment reflect volumes purchased, prices paid for supplies, and the mix of purchases from intercompany versus third party sources. Other operating costs and expenses of the gas distribution segment for the six months ended June 30, 2002 were higher than the comparable prior year period due primarily to a credit recorded in 2001 related to a settlement of issues with the Missouri Public Service Commission.

Marketing and Other

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Marketing revenues (in thousands)	$38,013	$54,628	$64,636	$125,660
Marketing operating income (in thousands)	$503	$444	$1,284	$1,587
Gas volumes marketed (Bcf)	12.4	12.4	24.6	23.4

Marketing
The decrease in gas marketing revenues for the three and six months ended June 30, 2002, relates to a substantial decrease in natural gas commodity prices from the prior year, and was largely offset by a comparable decrease in purchased gas costs. Operating income for the marketing segment was $1.3 million for the first six months of 2002, compared to $1.6 million for the same period in 2001. The Company marketed 24.6 Bcf of gas in the first six months of 2002, compared to 23.4 Bcf for the same period in 2001. The increase in volumes marketed resulted from an increase in volumes marketed for Southwestern's exploration and production subsidiaries.

NOARK Pipeline
The Company's share of the NOARK Pipeline System Limited Partnership (NOARK) pre-tax loss included in other income was $.4 million for the first six months of 2002, compared to $.8 million for the same period in 2001.

Interest Expense
Interest expense decreased 12% for the second quarter of 2002 and 16% for the first six months of 2002, both as compared to the same periods in 2001, due to lower average borrowings and a lower average interest rate, partially offset by a lower level of capitalized interest. Interest is capitalized in the exploration and production segment on costs that are unevaluated and excluded from amortization.

Income Taxes
The changes in the provisions for current and deferred income taxes recorded in the three and six month periods ended June 30, 2002, as compared to the same periods in 2001, resulted primarily from the decrease in the level of taxable income in 2002. 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.

Comprehensive Income
In the second quarter of 2002, the Company corrected its presentation of comprehensive income for prior quarters to properly reflect amounts associated with hedging activities. This change resulted in a decrease of $1.8 million to previously reported comprehensive income for the three months ended March 31, 2002 and an increase of $22.4 million for the six months ended June 30, 2001. The Company determined this correction in the presentation of comprehensive income is also warranted for the year ended December 31, 2001, increasing the amount previously reported by $22.9 million to yield corrected comprehensive income of $41.1 million. These corrections had no effect on the Company's previously reported net income, earnings per share or cash flows, nor did it have any impact on the Company's balance sheet. These corrections in the presentation of comprehensive income will be reflected in amendments to the Company's filings on Form 10-K and Form 10-Q that will be completed in the third quarter of 2002 in conjunction with the Company's change in auditors from Arthur Andersen LLP to PricewaterhouseCoopers LLP.

CHANGES IN FINANCIAL CONDITION

Changes in the Company's financial condition at June 30, 2002, as compared to December 31, 2001, primarily reflect changes in the Company's cash flow from operating activities, the seasonal nature of the Company's gas distribution segment, the timing of cash payments and receipts and the effects of accounting for the Company's hedging activities as required by SFAS No. 133.

The Company's cash flow from operating activities is highly dependent upon market prices that the Company receives for its gas and oil production. The price that the Company receives for its production is also heavily influenced by the Company's commodity hedging activities. Natural gas and oil prices are subject to wide fluctuations and have declined significantly in the first six months of 2002 as compared to prices received during the same period of 2001.

Routine capital expenditures have predominantly been funded through cash provided by operations. For the first six months of 2002 and 2001, cash provided by operating activities was $42.3 million and $84.4 million, respectively, and met or exceeded the total of these routine requirements.

Financing Requirements
In July 2001, the Company arranged an unsecured revolving credit facility with a group of banks. The revolving credit facility has a current capacity of $140 million and expires in July 2004. The interest rate on the current facility was 137.5 basis points over the current London Interbank Offered Rate (LIBOR), and was 4.6%, including the effects of interest rate swaps, at June 30, 2002. As of

July 8, 2002, the interest rate increased to 150 basis points over LIBOR as the result of a downgrade of the Company's public debt by Moody's from Baa3 to Ba2. Standard and Poor's continues to rate the Company's public debt at BBB.

The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 70% 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 3.75 or higher through December 31, 2002. These covenants change over the term of the credit facility and generally become more restrictive. At June 30, 2002, the Company's revolving credit facility had a balance of $119.5 million and was classified as long-term debt in the Company's balance sheet. The Company has also entered into interest rate swaps for calendar year 2002 that allow the Company to pay an average fixed interest rate of 4.9% (based upon current rates under the revolving credit facility) on $100.0 million of its outstanding revolving debt.

During the first six months of 2002, the Company's total debt decreased by $5.5 million. Total debt at June 30, 2002, accounted for 65.5% of the Company's capitalization (excluding the Company's several guarantee of NOARK's obligations). The percentage of debt to capitalization at June 30, 2002, would be 64.7% without consideration of the $6.4 million of accumulated other comprehensive loss recorded in the equity section of the Company's balance sheet. The other comprehensive loss in the June 30, 2002 balance sheet resulted from the Company's hedging activities and was recorded in accordance with the requirements of SFAS No. 133.

The Company's capital expenditures for the first six months of 2002 were $40.8 million, compared to $48.0 million for the same period in 2001. Planned capital investments during calendar year 2002 are currently expected to be approximately $78.0 million. The Company is in the process of marketing its Oklahoma properties in the Anadarko Basin. Proceeds from this sale may be used to increase capital investments within the exploration and production segment.

At June 30, 2002, the NOARK partnership had outstanding debt totaling $72.0 million. The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on the NOARK debt. The Company's share of the several guarantee is 60%.

Working Capital

Accounts receivable has declined since December 31, 2001, primarily due to the seasonality of the gas distribution segment's operations. Changes in accounts payable and other current assets and liabilities since December 31, 2001 are due primarily to the timing of expenditures and receipts. Over-recovered purchased gas costs for the Company's gas distribution segment were $6.7 million at June 30, 2002, compared to $8.2 million at December 31, 2001. Purchased gas costs are recovered from the Company's utility customers in subsequent months through automatic cost of gas adjustment clauses included in the utility's filed rate tariffs. At June 30, 2002, the Company had a current hedging asset of $4.3 million, a current hedging liability of $10.3 million, and a regulatory liability of $.9 million recorded as a result of the provisions of SFAS No. 133.

CRITICAL ACCOUNTING POLICIES

Oil and Gas Properties

The Company utilizes the full cost method of accounting for costs related to its oil and natural gas properties. The Company reviews the carrying value of its oil and gas properties under the full cost accounting rules of the Securities and Exchange Commission 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 oil and natural gas properties exceed the ceiling, the Company 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 oil and gas prices may subsequently increase the ceiling.

The risk that the Company will be required to write-down the carrying value of its oil and natural gas properties increases when oil and natural gas 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 oil and natural gas prices in effect on June 30, 2002, the unamortized cost of the Company’s oil and natural gas properties did not exceed the ceiling of proved oil and natural gas reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly reporting periods.

Oil and natural gas reserves used in the full cost method of accounting cannot be measured exactly. The Company’s estimate of oil and natural gas 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. The Company utilizes K&A Energy Consultants, Inc., independent petroleum consultants, to review reserves as prepared by the Company’s reservoir engineers.

Hedging

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 Company’s policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. The primary market risks related to the Company’s 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.

The Company's derivative instruments are accounted for under SFAS No. 133 and are recorded at fair value in its financial statements. The Company utilizes market-based quotes from its hedge counterparties to value these open positions. These valuations are recognized as assets or liabilities in the Company's balance sheet and, to the extent an open position is an effective cash flow hedge, the offset is recorded in other comprehensive income. Results of settled commodity hedging transactions are reflected in oil and gas sales and results of settled interest rate hedges are reflected in interest expense. Any ineffective hedge, derivative not qualifying for accounting treatment as a hedge, or any ineffective portion of a hedge is recognized immediately in earnings. Future market price volatility could create significant changes to the hedge positions recorded in the Company's financial statements. See Part I, Item 3 - Quantitative and Qualitative Disclosures about Market Risk for additional information regarding the Company's hedging activities.

Regulated Utility Operations

The Company's utility operations are subject to the rate regulation and accounting requirements of the Arkansas Public Service Commission. Allocations of costs and revenues to accounting periods for ratemaking and regulatory purposes may differ from bases 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 and there is none currently anticipated. However, should this occur, 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.

See further discussion of the Company's significant accounting policies in Note 1 of Notes to Consolidated Financial Statements in the Company's 2001 annual report on Form 10-K.

FORWARD LOOKING INFORMATION

All statements, other than historical 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. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, the timing and extent of changes in commodity prices for gas and oil, the timing and extent of the Company's success in discovering, developing, producing, and estimating reserves, property acquisition or divestiture activities that may occur, the effects of weather and regulation on the Company's gas distribution segment, increased competition, legal and economic factors, governmental regulation, the financial impact of accounting regulations for derivative instruments, changing market conditions, the comparative cost of alternative fuels, conditions in capital markets and changes in interest rates, availability of oil field services, drilling rigs and other equipment, as well as various other factors beyond the Company's control.

PART I

Item 3 - Quantitative and Qualitative Disclosures About Market Risk

Market risks relating to the Company's operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. 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.

Credit Risks

The Company's 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 6% of accounts receivable. See the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

The Company's revolving debt obligations are sensitive to changes in interest rates. The Company's 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. The Company has entered into interest rate swaps for calendar year 2002 that allow the Company to pay an average fixed interest rate of 4.9% (based upon current rates under the revolving credit facility) on $100.0 million of its outstanding revolving debt. The Company's revolving debt was $125.0 million at December 31, 2001, and had an average interest rate of 3.4%. At June 30, 2002, the Company's revolving debt was $119.5 million with an average interest rate of 4.6%, including the effect of the interest rate swaps. Other than the Company's revolving debt, there have been no material changes in the interest rate risk information that was presented in the Company's 2001 annual report on Form 10-K.

The Company's interest rate swaps have a carrying amount of $1.9 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 the Company's financial statements. The fair value of $1.0 million represents the value for the same contracts using comparable market prices at June 30, 2002. At June 30, 2002, the "Carrying Amount" exceeded the "Fair Value" of interest rate swaps by $.9 million.

Commodities Risk

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.

The primary market risks related to the Company's 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 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.

The following table provides information about the Company's 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 the Company's financial statements. The "Fair Value" represents values for the same contracts using comparable market prices at June 30, 2002. At June 30, 2002, the "Carrying Amount" exceeded the "Fair Value" of these financial instruments by $9.3 million.

	Expected Maturity Date					
	2002		2003		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Production and Marketing						
Natural Gas:						
Swaps with a fixed price receipt						
Contract volume (Bcf)	7.4		13.3		3.2	
Weighted average price per Mcf	$3.03		$3.47		$3.99	
Contract amount (in millions)	$22.4	$19.1	$46.2	$40.8	$12.8	$12.8
Swaps with a fixed price payment						
Contract volume (Bcf)	.1		-		-	
Weighted average price per Mcf	$3.30		-		-	
Contract amount (in millions)	$.1	$.1	-	-	-	-
Price collars						
Contract volume (Bcf)	7.4		15.8		4.0	
Weighted average floor price per Mcf	$3.29		$3.16		$3.25	
Contract amount of floor (in millions)	$24.4	$26.8	$50.1	$54.2	$13.0	$14.3
Weighted average ceiling price per Mcf	$4.30		$4.84		$4.75	
Contract amount of ceiling (in millions)	$31.9	$31.0	$76.7	$71.2	$19.0	$17.1
Oil:						
Swaps with a fixed price receipt						
Contract volume (MBbls)	167		-		-	
Weighted average price per Bbl	$20.07		-		-	
Contract amount (in millions)	$3.3	$2.3	-	-	-	-
Natural Gas Purchases						
Swaps with a fixed price payment						
Contract volume (Bcf)	.7		1.3		-	
Weighted average price per Mcf	$3.30		$3.30		-	
Contract amount (in millions)	$2.3	$2.6	$4.4	$5.0	-	-

PART II

OTHER INFORMATION

Items 1 - 3

No developments required to be reported under Items 1 - 3 occurred during the quarter ended June 30, 2002.

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

The Company held its Annual Meeting of Shareholders on May 15, 2002, for the purposes of (1) electing Directors of the Company for the ensuing year, and (2) to approve an amendment to the Company's Amended and Restated Articles of Incorporation to provide for the authority to issue, from time to time, up to 10,000,000 shares of preferred stock with such rights, preferences and priorities as the Board of Directors shall designate. Holders of 22,996,229 shares (90.2% of total outstanding shares) voted in total.

Holders of 20,611,551 shares voted for the election of directors and 2,384,678 shares voted as withheld. The Directors were elected with the number of shares voted as follows:

	Voted For	Withheld
Lewis E. Epley, Jr.	20,568,406	2,402,178
John Paul Hammerschmidt	20,559,700	2,410,884
Robert L. Howard	20,566,928	2,403,656
Harold M. Korell	19,134,818	3,989,636
Kenneth R. Mourton	20,574,564	2,396,020
Charles E. Scharlau	20,409,382	2,561,202

The amendment to the Company's Amended and Restated Articles of Incorporation to provide for the authority to issue preferred stock was approved with the following vote count:

For	11,886,297
Against	8,108,137
Abstain	76,150
Non-vote	2,925,645

Items 5 - 6(a)

No developments required to be reported under Items 5 - 6(a) occurred during the quarter ended June 30, 2002.

Item 6(b)

On April 23, 2002, the Company filed a current report on Form 8-K, and on April 24, 2002, filed an amended Form 8-K, containing the transcript of the Company's conference call on April 22, 2002 discussing the Company's results for the first quarter of 2002.

On April 24, 2002, the Company filed a current report on Form 8-K containing the Company's slide presentation made to investors on April 23, 2002 at the IPAA Oil & Gas Investment Symposium in New York, New York.

On May 15, 2002, the Company filed a current report on Form 8-K announcing the approval of an additional $10 million in its 2002 capital budget.

On June 21, 2002, the Company filed a current report on Form 8-K announcing the appointment of PricewaterhouseCoopers LLP as its independent accountant for 2002 and the dismissal of Arthur Andersen LLP as its independent auditor.

On July 29, 2002, the Company filed a current report on Form 8-K, and on July 30, 2002, filed an amended Form 8-K, containing the transcript of the Company's conference call on July 25, 2002 discussing the Company's results for the second quarter of 2002.

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: August 14, 2002

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