

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q/A

(Mark one)

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities
Exchange Act of 1934
For the quarterly period ended March 31, 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
(State of incorporation
or organization
No.)

71-0205415
(I.R.S. Employer
Identification

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 April 15, 2002
----- Common Stock, Par Value \$.10	----- 25,599,140

=====

Explanatory Note:

This form 10-Q/A amends our Quarterly Report on Form 10-Q filed on April 19, 2002. We have included certain changes in this Form 10-Q/A in order to correct the presentation of comprehensive income for the three month periods ended March 31, 2002 and 2001, to properly reflect amounts associated with hedging activities (see Note 1 to the accompanying financial statements). This correction 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. Except as set forth in the preceding sentences, we have not materially updated or revised the information in our Quarterly Report.

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PART I
FINANCIAL INFORMATION

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Unaudited)

ASSETS

	March 31,	December
31,	2002	2001
-----	-----	-----
	(\$ in thousands)	
Current Assets		
Cash	\$ 1,315	\$ 3,641
Accounts receivable	41,771	42,763
Inventories, at average cost	24,547	26,606
Hedging asset - SFAS No.133	4,008	9,381
Regulatory asset - hedges	-	5,817
Other	4,318	4,996
	-----	-----
Total current assets	75,959	93,204
	-----	-----
Investments	15,338	15,538
	-----	-----
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method	990,528	970,680
Gas distribution systems	193,567	192,784
Gas in underground storage	27,999	32,046
Other	30,339	30,110
	-----	-----
	1,242,433	1,225,620
	-----	-----
Less: Accumulated depreciation, depletion and amortization	619,581	605,790
	-----	-----
	622,852	619,830
	-----	-----
Other Assets	13,533	14,551
	-----	-----
Total Assets	\$ 727,682	\$ 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

	March 31, 2002	December 2001
31,		

	(\$ in thousands)	
Current Liabilities		
Accounts payable	29,403	41,644
Taxes payable	4,494	4,400
Interest payable	6,604	2,653
Customer deposits	4,889	4,845
Hedging liability - SFAS No. 133	12,641	6,990
Over-recovered purchased gas costs	7,953	8,184
Other	3,726	2,752
	-----	-----
Total current liabilities	69,710	71,468
	-----	-----
Long-Term Debt	342,700	350,000
	-----	-----
Other Liabilities		
Deferred income taxes	117,815	122,381
Other	6,969	3,187
	-----	-----
	124,784	125,568
	-----	-----
Commitments and Contingencies		
Minority Interest in Partnership	13,294	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	19,358	19,764
Retained earnings	190,392	183,677
Accumulated other comprehensive income (loss)	(7,825)	5,763
	-----	-----
	204,699	211,978
Less: Common stock in treasury, at cost, 2,158,379 shares in 2002 and 2,261,766 shares in 2001	24,045	25,196
Unamortized cost of 422,203 restricted shares in 2002 and 416,537 restricted shares in 2001, issued under stock incentive plan	3,460	3,696
	-----	-----
	177,194	183,086
	-----	-----
Total Liabilities and Shareholders' Equity	\$ 727,682	\$ 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 March 31,	
	2002	2001
	(\$ in thousands, except per share amounts)	
Operating Revenues		
Gas sales	\$ 66,986	\$ 95,385
Gas marketing	9,702	35,189
Oil sales	3,183	4,162
Gas transportation and other	1,787	2,393
	-----	-----
	81,658	137,129
	-----	-----
Operating Costs and Expenses		
Gas purchases - utility	24,768	41,128
Gas purchases - marketing	8,673	33,735
Operating expenses	9,558	10,463
General and administrative expenses	5,790	4,827
Depreciation, depletion and amortization	13,870	11,637
Taxes, other than income taxes	2,160	2,740
	-----	-----
	64,819	104,530
	-----	-----
Operating Income	16,839	32,599
	-----	-----
Interest Expense		
Interest on long-term debt	5,354	6,867
Other interest charges	322	291
Interest capitalized	(291)	
(436)		
	-----	-----
	5,385	6,722
	-----	-----
Other Income (Expense)	(242)	380
	-----	-----
Income Before Income Taxes & Minority Interest	11,212	26,257
	-----	-----
Minority Interest in Partnership	(293)	-
	-----	-----
Income Before Income Taxes	10,919	26,257
	-----	-----
Income Tax Provision		
Current	-	-
Deferred	4,204	10,244
	-----	-----
	4,204	10,244
	-----	-----
Net Income	\$ 6,715	\$ 16,013
	=====	=====
Basic Earnings Per Share	\$0.26	\$0.64
	=====	=====
Basic Average Common Shares Outstanding	25,499,294	25,187,103
	=====	=====
Diluted Earnings Per Share	\$0.26	\$0.63
	=====	=====
Diluted Average Common Shares Outstanding	25,859,247	25,495,585
	=====	=====

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

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31,	
	2002	2001
	(\$ in thousands)	
Cash Flows From Operating Activities		
Net income	\$ 6,715	\$ 16,013
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	14,472	12,012
Deferred income taxes	4,204	10,244
Equity in loss of NOARK partnership	200	305
Minority interest in partnership	293	-
Change in assets and liabilities:		
Accounts receivable	803	8,248
Inventories	2,059	
Accounts payable	(12,241)	
Taxes payable	94	2,117
Interest payable	3,951	3,258
Other current assets and liabilities	802	1,915
Net cash provided by operating activities	21,352	40,407
Cash Flows From Investing Activities		
Capital expenditures	(21,369)	
Change in gas stored underground	4,047	2,534
Other items	944	1,806
Net cash used in investing activities	(16,378)	
Cash Flows From Financing Activities		
Net change in revolving long-term debt	(7,300)	
Net cash used in financing activities	(7,300)	
Increase (decrease) in cash	(2,326)	233
Cash at beginning of year	3,641	2,386
Cash at end of period	\$ 1,315	\$ 2,619

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 March 31,	
	2002*	2001*

	(\$ in thousands)	
Net income	\$ 6,715	\$ 16,013
Other comprehensive income (loss):		
Transition adjustment from adoption of SFAS No. 133	-	
(36,963)		
Change in value of derivative instruments	(13,588)	24,790

Comprehensive Income (Loss)	\$ (6,873)	\$ 3,840
	=====	
Reconciliation of Accumulated Other Comprehensive Income (Loss):		
Balance, Beginning of Period	\$ 5,763	\$ -
Cumulative effect of adoption of SFAS No. 133 (36,963)	-	
Current period reclassification to earnings	(1,776)	20,546
Current period change in derivative instruments	(11,812)	4,244

Balance, End of Period	\$ (7,825)	
\$(12,173)		
	=====	

* The 2002 and 2001 Consolidated Statements of Comprehensive Income (Loss) were restated to correct the presentation of comprehensive income, as discussed in Footnote 1 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

MARCH 31, 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 accounting policies are summarized in the 2001 Annual Report on Form 10-K, Item 8, Notes to Consolidated Financial Statements.

Southwestern, in the accompanying financial statements, has corrected its presentation of comprehensive income for the quarters ended March 31, 2002 and March 31, 2001, 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 \$20.5 million to previously reported comprehensive income for the three months ended March 31, 2001. This correction 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.

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 March 31, 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 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. The Company had options for 1,033,634 shares of common stock with a weighted average exercise price of \$13.68 per share at March 31, 2002, and options for 1,109,882

shares with an average exercise price of \$13.55 per share at March 31, 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 a new unsecured revolving credit facility with a group of banks to replace its existing short-term credit facility that was put in place in July 2000. The new revolving credit facility has a capacity of \$155 million and a three-year term. The interest rate on the new facility is 137.5 basis points over the current London Interbank Offered Rate (LIBOR), and was 4.59%, including the effects of interest rate swaps, at March 31, 2002. The new 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 March 31, 2002, the Company's revolving credit facility had a balance of \$117.7 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 4.8% (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 March 31, 2002, the Company's net liability related to its cash flow hedges was \$12.4 million. Additionally, at March 31, 2002, the Company had recorded a net of tax cumulative loss to other comprehensive income (equity section of the balance sheet) of \$7.8 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 retail transportation and sale of

natural gas. 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 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	534,314	156,952	9,380	27,036 (2)	727,682
Capital expenditures	19,881 (3)	1,348	--	140	21,369 (3)
Three months ended March 31, 2001:					
Revenues from external customers	\$ 20,577	\$ 81,363	\$ 35,189	\$ --	\$ 137,129
Intersegment revenues	20,163	129	35,843	112	56,247
Operating income	21,988	9,398	1,143	70	32,599
Depreciation, depletion and amortization expense	10,046	1,551	17	23	11,637
Interest expense (1)	5,322	1,092	33	275	6,722
Provision (benefit) for income taxes (1)	6,501	3,403	433	(93)	10,244
Assets	464,260	184,697	18,523	36,043 (2)	703,523
Capital expenditures	14,299	909	--	106	15,314

(1) Interest expense and the provision (benefit) for income taxes by segment is an allocation of corporate amounts as debt and income tax expense (benefit) 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 includes \$2.7 million for the three months ended March 31, 2002, related to the consolidated results of a limited partnership.

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 pension 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.

7. 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.

Quarters Ended March 31	2002	2001
	(in thousands)	
Interest payments	\$1,405	\$3,615
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 March 31, 2002 and December 31, 2001, the principal outstanding for these Notes was \$73.0 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 2002 and 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 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 month period ended March 31, 2002, and the comparable period of 2001.

RESULTS OF OPERATIONS

Southwestern reported net income of \$6.7 million, or \$.26 per share on a fully diluted basis, for the three months ended March 31, 2002, compared to \$16.0 million, or \$.63 per share, for the same period in 2001. The decrease in earnings primarily resulted from lower natural gas prices experienced by the Company's exploration and production segment, partially offset by an increase in production volumes.

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 March 31,	
	2002	2001
Revenues (in thousands)	\$28,420	\$40,740
Operating income (in thousands)	\$7,330	\$21,988
Gas production (MMcf)	9,231	8,026
Oil production (MBbls)	182.8	161.0
Total production (MMcfe)	10,329	8,992
Average gas price per Mcf	\$2.76	\$4.48
Average oil price per Bbl	\$17.41	\$25.82
Operating expenses per Mcfe		
Production expenses	\$0.43	\$0.51
Production taxes	\$0.15	\$0.23
General & administrative expenses	\$0.27	\$0.22
Full cost pool amortization	\$1.16	\$1.08

Revenues and Operating Income

Revenues for the exploration and production segment were down 30% for the three-month period ended March 31, 2002 compared to the same period in 2001. The decrease was due to lower gas and oil prices received for the Company's production, partially offset by increased production volumes.

Operating income for the exploration and production segment was down \$14.7 million for the three months ended March 31, 2002, compared to the same period in 2001. The decrease in operating income resulted from the decline in revenues and an increase in depreciation, depletion and amortization expense.

Production

Gas and oil production during the first quarter of 2002 was 10.3 billion cubic feet (Bcf) equivalent, up from 9.0 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 9.2 Bcf for the first three months of 2002, compared to 8.0 Bcf for the same period in 2001. The Company's sales to its gas distribution systems were 1.9 Bcf during the three months ended March 31, 2002, compared to 2.3 Bcf for the same period in 2001. The Company's oil production was 182.8 thousand barrels (MBbls) during the first quarter of 2002, up from 161.0 MBbls for the same period of 2001.

Commodity Prices

The Company received an average price of \$2.76 per thousand cubic feet (Mcf) for its gas production for the three months ended March 31, 2002, down from \$4.48 per Mcf for the same period of 2001. The Company hedged 4.7 Bcf of gas production in the first three months of 2002 through fixed-price swaps and zero-cost collars which had the effect of increasing the average gas price realized during the period by \$.44 per Mcf. On a comparative basis, the average price during the first three months of 2001 included the negative effect of hedges that decreased the average price by \$2.73 per Mcf.

For the remainder of the year 2002, the Company has 9.4 Bcf of gas production hedged with collars having an average NYMEX floor price of \$3.24 per Mcf and an average NYMEX ceiling price of \$4.07 per Mcf. The Company also has 12.2 Bcf of gas production for the remainder of 2002 hedged with fixed price swaps at an average NYMEX price of \$2.82 per Mcf. For 2003 and 2004, the Company has 23.1 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 \$17.41 per barrel for its oil production during the three months ended March 31, 2002, down from \$25.82 per barrel for the same period of 2001. For the remainder of 2002, the Company has a hedge on 249,750 barrels at an average NYMEX price of \$20.07 per barrel.

Operating Costs and Expenses

Operating costs and expenses for the exploration and production segment increased in the first three months of 2002 due to increased depreciation, depletion and amortization expense and higher general and administrative expenses, partially offset by a decrease in production costs and severance taxes. The increase in depreciation, depletion and amortization expense was due to the increase in production and an increase in the amortization rate per unit of production. The full cost pool amortization rate

averaged \$1.16 per Mcf equivalent for the first three months of 2002, compared to \$1.08 per Mcf equivalent in the first three months of 2001. The increase in general and administrative expenses in 2002 resulted from increases in compensation expense and corporate overhead costs. The decrease in production costs was primarily due to a decrease in workover expenses as compared to 2001. Severance taxes decreased during the quarter due to lower average prices received for the Company's production.

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 March 31, 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.

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 March 31,	
	2002	2001
amounts)	(\$ in thousands, except for Mcf	
Revenues	\$48,457	\$81,492
Gas purchases	\$29,618	\$61,289
Operating costs and expenses	\$10,176	\$10,805
Operating income	\$8,663	\$9,398
Deliveries (Bcf)		
Sales and end-use transportation	10.1	10.5
Off-system transportation	--	--

Average number of customers	138,071
136,621	
Average sales rate per Mcf	\$5.98
\$9.32	
Heating weather - degree days	2,049
2,161	
- percent of normal	95%
100%	

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 months ended March 31, 2002 are down from the comparable period 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 quarter of 2001. The decrease in gas cost was reflected in the Company's average rate for its utility sales which decreased during the first three months of 2002 to \$5.98 per Mcf, down from \$9.32 per Mcf for the same period in 2001. Costs paid for purchases of natural gas are passed through to customers under automatic adjustment clauses.

Operating income of the gas distribution segment decreased 8% in the first quarter of 2002, as compared to the same period of 2001. The decrease was primarily due to warmer weather. Weather during the first quarter of 2002 was 5% warmer than both normal and the same period of 2001. The weather normalization clause in the Company's rates lessens the impacts of revenue increases and decreases that might result from weather variations during the winter heating season.

Deliveries

The utility systems delivered 10.1 Bcf to sales and end-use transportation customers during the three months ended March 31, 2002, down from 10.5 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 quarter ended March 31, 2002 were lower than the comparable period of the prior year due primarily to a decrease in the average cost of fuel purchased for compression operations.

Marketing and Other

	Three Months Ended March 31,	
-----	2002	2001

Marketing revenues (in thousands)	\$26,623	\$71,032
Marketing operating income (in thousands)	\$781	\$1,143
Gas volumes marketed (Bcf)	12.3	11.0

Marketing

The decrease in gas marketing revenues for the quarter ended March 31, 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 \$.8 million for the first three months of 2002, compared to \$1.1 million for the same period in 2001. The Company marketed 12.3 Bcf of gas in the first three months of 2002, compared to 11.0 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) pretax loss included in other income was \$.2 million for the first quarter of 2002, compared to \$.3 million for the same period in 2001.

Interest Expense

Interest expense decreased 20% for the first quarter of 2002, compared to the same period 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 provision for deferred income taxes recorded in the three months ended March 31, 2002, as compared to the same period 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.

CHANGES IN FINANCIAL CONDITION

Changes in the Company's financial condition at March 31, 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 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 quarter of 2002 as compared to prices received during 2001.

Routine capital expenditures have predominantly been funded through cash provided by operations. For the first three months of 2002 and 2001, cash provided by operating activities was \$21.4 million and \$40.4 million, respectively, and met or exceeded the total of these routine requirements.

Financing Requirements

In July 2001, the Company arranged a new 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 new revolving credit facility has a current capacity of \$155 million and expires in July 2004. The interest rate on the current facility is 137.5 basis points over the current London Interbank Offered Rate (LIBOR), and was 4.59%, including the effects of interest rate swaps, at March 31, 2002. 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 March 31, 2002, the Company's revolving credit facility had a balance of \$117.7 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 4.8% (based upon current rates under the revolving credit facility) on \$100.0 million of its outstanding revolving debt.

During the first three months of 2002, the Company's total debt decreased by \$7.3 million. Total debt at March 31, 2002, accounted for 66% of the Company's capitalization. The percentage of debt to capitalization at March 31, 2002, would be 65% without consideration of the \$7.8 million of accumulated other comprehensive loss recorded in the equity section of the Company's balance sheet. The other comprehensive loss in the March 31, 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 three months of 2002 were \$21.4 million, compared to \$15.3 million for the same period in 2001. Capital investments during calendar year 2002 are currently expected to be approximately \$68.0 million. The Company may adjust its level of future capital investments dependent upon the level of cash flow generated from operations.

At March 31, 2002, the NOARK partnership had outstanding debt totaling \$73.0 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 slightly since December 31, 2001, primarily due to the seasonality of the gas distribution segment's operations. Changes in accounts payable, interest 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 \$8.0 million at March 31, 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 March 31, 2002, the Company had a current hedging asset of \$4.0 million, a current hedging liability of \$12.6 million, and a regulatory liability of \$.9 million recorded as a result of the provisions of SFAS No. 133.

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.

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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 3% 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 4.8% (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 3.44%. At March 31, 2002, the Company's revolving debt was \$117.7 million with an average interest rate of 4.59%, 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 Form 10-K.

The Company's interest rate swaps have a carrying amount of \$2.7 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 the Company's financial statements. The fair value of \$2.0 million represents the value for the same contracts using comparable market prices at March 31, 2002. At March 31, 2002, the "Carrying Amount" exceeded the "Fair Value" of interest rate swaps by \$.7 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 March 31, 2002. At March 31, 2002, the "Carrying Amount" exceeded the "Fair Value" of these financial instruments by \$11.7 million.

	Expected Maturity Date					
	2002		2003		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Natural Gas:						

Swaps with a fixed price receipt						
Contract volume (Bcf)	12.2		9.2		-	
Weighted average price per Mcf	\$2.82		\$3.18		-	
Contract amount (in millions)	\$34.5	\$27.2	\$29.3	\$24.8	-	-
Swaps with a fixed price payment						
Contract volume (Bcf)	.1		-		-	
Weighted average price per Mcf	\$2.19		-		-	
Contract amount (in millions)	\$.2	\$.3	-	-	-	-
Price collar						
Contract volume (Bcf)	9.4		9.9		4.0	
Weighted average floor price per Mcf	\$3.24		\$3.11		\$3.25	
Contract amount of floor (in millions)	\$30.6	\$34.3	\$30.6	\$34.2	\$13.0	\$14.8
Weighted average ceiling price per Mcf	\$4.07		\$4.71		\$4.75	
Contract amount of ceiling						

(in millions)	\$38.4	\$35.9	\$46.4	\$42.2	\$19.0	\$17.3
Oil:						
Swaps with a fixed price receipt						
Contract volume (MBbls)	250		-		-	
Weighted average price per Bbl	\$20.07		-		-	
Contract amount (in millions)	\$5.6	\$4.0	-	-	-	-
Natural Gas Purchases:						
Swaps with a fixed price payment						
Contract volume (Bcf)	.3		.7		-	
Weighted average price per Mcf	\$2.91		\$2.91		-	
Contract amount (in millions)	\$1.0	\$1.3	\$1.9	\$2.5	-	-

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PART II

OTHER INFORMATION

Items 1 - 6(a)

No developments required to be reported under Items 1 - 6(a) occurred during the quarter ended March 31, 2002.

Item 6(b)

On February 19, 2002, the Company filed a current report on Form 8-K containing the transcript of the Company's conference call on February 15, 2002 discussing the Company's results for the fourth quarter and year-ended December 31, 2001.

On March 21, 2002, the Company filed a current report on Form 8-K containing the Company's slide presentation made to investors on March 20, 2002 at the CIBC World Markets Annual Energy Conference in New York, New York, and discussing the Company's 2001 results and outlook and business strategy for 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: *September 24, 2002*

/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 amended quarterly report on Form 10-Q/A of Southwestern Energy Company;
2. Based on my knowledge, this amended 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 amended quarterly report; and
3. Based on my knowledge, the financial statements, and other financial information included in this amended 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 amended quarterly report.

Date: September 24, 2002

/s/ HAROLD M. KORELL

Harold M. Korell
Chief Executive Officer

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CERTIFICATION

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

1. I have reviewed this amended quarterly report on Form 10-Q/A of Southwestern Energy Company;
2. Based on my knowledge, this amended 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 amended quarterly report; and
3. Based on my knowledge, the financial statements, and other financial information included in this amended 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 amended quarterly report.

Date: September 24, 2002

/s/ GREG D. KERLEY

Greg D. Kerley
Chief Financial Officer

End of Filing