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

FORM 10-Q

(Mark one)

[X] Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **March 31, 2006**

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 **1-08246**

Southwestern Energy Company

SOUTHWESTERN ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Arkansas	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 N. Sam Houston Pkwy. E., Suite 300, Houston, Texas	**77032**
(Address of principal executive offices)	(Zip Code)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes: X No: ___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated Filer X   Accelerated filer ___   Non-accelerated filer ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes: ___ No: X

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 24, 2006
Common Stock, Par Value $0.10	167,644,891

PART I

FINANCIAL INFORMATION

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended March 31, 2006	2005	
	(in thousands, except share/per share amounts)		
Operating Revenues:			
Gas sales	$ 180,798	$ 126,271	
Gas marketing	30,965	24,547	
Oil sales	10,035	6,111	
Gas transportation and other	4,904	4,124	
	226,702	161,053	
Operating Costs and Expenses:			
Gas purchases - gas distribution	45,356	33,823	
Gas purchases - midstream services	28,427	23,198	
Operating expenses	14,391	11,933	
General and administrative expenses	14,553	10,303	
Depreciation, depletion and amortization	28,103	20,247	
Taxes, other than income taxes	6,068	5,323	
	136,898	104,827	
Operating Income	89,804	56,226	
Interest Expense:			
Interest on long-term debt	2,177	4,923	
Other interest charges	326	310	
Interest capitalized	(2,358)	(695)	
	145	4,538	
Other Income	3,176	184	
Income Before Income Taxes and Minority Interest	92,835	51,872	
Minority Interest in Partnership	(291)	(93)	
Income Before Income Taxes	92,544	51,779	
Provision for Income Taxes - Deferred	34,149	19,158	
Net Income	$ 58,395	$ 32,621	
Earnings Per Share:			
Basic	$ 0.35	$ 0.23	(1)
Diluted	$ 0.34	$ 0.22	(1)
Weighted Average Common Shares Outstanding:			
Basic	166,777,560	144,503,440	(1)
Diluted	170,946,501	149,824,508	(1)

(1) Restated to reflect the two-for-one stock splits effected on June 3, 2005 and November 17, 2005.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

ASSETS

	March 31, 2006	December 31, 2005
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 212,363	$ 223,705
Accounts receivable	90,570	128,948
Inventories, at average cost	34,041	49,513
Deferred income tax benefit	5,476	29,700
Hedging asset - FAS 133	27,392	17,467
Other	8,147	11,731
Total current assets	377,989	461,064
Investments	18,025	17,100
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $131,067,810 in 2006 and $115,195,700 in 2005 excluded from amortization	2,028,426	1,897,613
Gas distribution systems	219,833	216,644
Construction-in-progress - drilling rigs and equipment	36,871	35,128
Drilling rigs and equipment - in service	21,322	-
Gathering systems	20,443	15,742
Gas in underground storage	32,254	32,254
Other	49,805	45,234
	2,408,954	2,242,615
Less: Accumulated depreciation, depletion and amortization	900,376	872,218
	1,508,578	1,370,397
Other Assets	27,292	19,963
Total Assets	$ 1,931,884	$ 1,868,524

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	March 31, 2006	December 31, 2005
	(in thousands)	
Current Liabilities		
Accounts payable	$ 125,490	$ 154,385
Taxes payable	10,959	14,519
Customer deposits	6,454	6,352
Hedging liability - FAS 133	48,616	112,293
Over-recovered purchased gas costs	8,871	7,323
Other	9,279	7,514
Total current liabilities	209,669	302,386
Long-Term Debt	100,000	100,000
Other Liabilities		
Deferred income taxes	298,542	254,528
Long-term hedging liability	45,120	60,442
Other	30,397	29,251
	374,059	344,221
Commitments and Contingencies		
Minority Interest in Partnership	11,905	11,613
Shareholders' Equity		
Common stock, $0.10 par value; authorized 220,000,000 shares, issued 168,452,336 shares	16,845	16,845
Additional paid-in capital	707,521	711,196
Retained earnings	556,616	498,221
Accumulated other comprehensive income (loss)	(42,459)	(104,874)
Common stock in treasury, at cost, 815,859 shares at March 31, 2006 and 1,217,284 shares at December 31, 2005	(2,272)	(3,390)
Unamortized cost of restricted shares issued under stock incentive plan, 707,142 shares at December 31, 2005	-	(7,694)
	1,236,251	1,110,304
Total Liabilities and Shareholders' Equity	$ 1,931,884	$ 1,868,524

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

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

	For the three months ended March 31, 2006	2005
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 58,395	$ 32,621
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	28,403	20,617
Deferred income taxes	34,149	19,158
Unrealized loss on derivatives	4,056	636
Stock-based compensation expense	1,000	640
Equity in income of NOARK partnership	(925)	(149)
Minority interest in partnership	291	93
Change in operating assets and liabilities:		
Accounts receivable	38,378	9,248
Inventories	15,472	16,012
Under/over-recovered purchased gas costs	1,548	7,595
Accounts payable	(36,224)	(6,724)
Taxes payable	(3,560)	(1,013)
Interest payable	1,576	4,058
Other operating assets and liabilities	810	307
Net cash provided by operating activities	143,369	103,099
Cash Flows From Investing Activities		
Capital expenditures	(156,421)	(80,361)
Proceeds from sale of property, plant and equipment	65	700
Other items	169	517
Net cash used in investing activities	(156,187)	(79,144)
Cash Flows From Financing Activities		
Payments on revolving long-term debt	-	(105,200)
Borrowings under revolving long-term debt	-	78,200
Debt issuance costs	-	(1,180)
Stock option tax benefit	2,562	-
Change in bank drafts outstanding	(2,235)	3,191
Proceeds from exercise of common stock options	1,149	656
Net cash provided by (used in) financing activities	1,476	(24,333)
Decrease in cash and cash equivalents	(11,342)	(378)
Cash and cash equivalents at beginning of year	223,705	1,235
Cash and cash equivalents at end of period	$ 212,363	$ 857

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

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

	Common Stock		Additional		Accumulated Other	Common	Unamortized Restricted	
	Shares Issued	Amount	Paid-In Capital	Retained Earnings	Comprehensive Income (Loss)	Stock in Treasury	Stock Awards	Total
					(in thousands)			
Balance at December 31, 2005	168,452	$ 16,845	$ 711,196	$ 498,221	$ (104,874)	$ (3,390)	$ (7,694)	$ 1,110,304
Comprehensive income:								
Net income	-	-	-	58,395	-	-	-	58,395
Change in value of derivatives	-	-	-	-	62,415	-	-	62,415
Total comprehensive income	-	-	-	-	-	-	-	120,810
Adoption of FAS 123(R)	-	-	(7,694)	-	-	-	7,694	-
Exercise of stock options	-	-	31	-	-	1,118	-	1,149
Tax effect of stock-based compensation	-	-	2,562	-	-	-	-	2,562
Issuance of restricted stock	-	-	(37)	-	-	37	-	-
Cancellation of restricted stock	-	-	37	-	-	(37)	-	-
Stock-based compensation - FAS 123(R)	-	-	1,426	-	-	-	-	1,426
Balance at March 31, 2006	168,452	$ 16,845	$ 707,521	$ 556,616	$ (42,459)	$ (2,272)	$ -	$ 1,236,251

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the three months ended March 31,	
	2006	2005
	(in thousands)	
Balance, beginning of period	$ (104,874)	$ (19,816)
Current period reclassification to earnings	(6,230)	1,239
Current period change in derivative instruments	68,645	(40,255)
Balance, end of period	$ (42,459)	$ (58,832)

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
March 31, 2006

(1) BASIS OF PRESENTATION

The financial statements included herein are unaudited; however, such information reflects all adjustments (consisting solely of normal recurring adjustments) which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. The Company's significant accounting policies are summarized in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (the "2005 Annual Report on Form 10-K").

Historical per share information provided as of March 31, 2005 in the financial statements and footnotes has been adjusted to reflect the two-for-one stock splits effected on June 3, 2005 and November 17, 2005.

As discussed below in Note 9, the Company adopted Statement of Financial Accounting Standards No. 123(R) “Share-Based Payment” (FAS123(R)), effective January 1, 2006. The Company adopted the modified prospective transition method provided under FAS 123(R) and consequently has not restated the presentation of the results for prior periods. Additionally, the Company is currently evaluating alternative methods of calculating the historical pool of windfall tax benefits as permitted by FASB Staff Position No. FAS123(R)-3, “Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards.” The realization of tax benefits from stock-based compensation in excess of amounts recognized for financial reporting purposes is recognized as a financing activity in the accompanying Consolidated Statements of Cash Flows.

(2) GAS AND OIL PROPERTIES

The Company follows the full cost method of accounting for the exploration, development, and acquisition of gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits, and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. The Company’s unamortized costs of natural gas and oil properties are limited to the sum of the future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. If the Company’s unamortized costs in natural gas and oil properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. At March 31, 2006, the Company’s net book value of natural gas and oil properties did not exceed the ceiling amount. At March 31, 2006, our standardized measure was calculated based upon quoted market prices of $7.18 per Mcf for Henry Hub gas and $66.63 per barrel for West Texas Intermediate oil, adjusted for market differentials. Decreases in market prices from March 31, 2006 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could result in future ceiling test impairments.

(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 period. The diluted earnings per share calculation, using the average market price of our common stock for the period and the treasury stock method per FAS 128, “Earnings Per Share” (as amended), adds to the weighted average number of common shares outstanding the incremental number of shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock.

For the first three months ended March 31, 2006, 6,498,521 of the Company’s outstanding options with an average exercise price of $3.34 were included in the calculation of diluted shares. Options for 223,780 shares were excluded from the calculation because they would have had an antidilutive effect. Outstanding options for 8,642,368 shares at March 31, 2005, with a weighted average exercise price of $3.19, were included in the calculation of diluted shares. Restricted shares included in the calculation of diluted shares were 547,579 and 795,196 at March 31, 2006 and 2005, respectively. At March 31, 2006, 109,414 shares of restricted stock were excluded from the calculation because they would have had an antidilutive effect. The number of options and the exercise prices, and the number of restricted shares have been adjusted to reflect the two-for-one stock splits effected in the second and fourth quarters of 2005.

(4) DEBT

Debt balances as of March 31, 2006 and December 31, 2005 consisted of the following:

	March 31, 2006	December 31, 2005
	(in thousands)	
Senior notes:		
7.625% Series due 2027, putable at the holders' option in 2009	$ 60,000	$ 60,000
7.21% Series due 2017	40,000	40,000
Total debt	$ 100,000	$ 100,000

The Company has a $500 million unsecured revolving credit facility that expires in January 2010. There were no amounts outstanding under the revolving credit facility at March 31, 2006 and December 31, 2005. The interest rate on the credit facility is calculated based upon the Company's debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). 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 60% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company's subsidiaries to incur debt. At March 31, 2006, the Company's capital structure consisted of 7% debt (excluding its several guarantee of NOARK's obligations) and 93% equity, with a ratio of EBITDA to interest expense of 36.1, and the Company was in compliance with its debt agreements.

(5) DERIVATIVES AND RISK MANAGEMENT

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 137, FAS 138 and FAS 149, was adopted by the Company on January 1, 2001. FAS 133 requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement.

At March 31, 2006, the Company's net liability related to its cash flow hedges was $57.0 million. Additionally, at March 31, 2006, the Company had recorded a cumulative loss to other comprehensive income net of tax (equity section of the balance sheet) of $37.4 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. Assuming the market prices of futures as of March 31, 2006 remain unchanged, the Company would expect to transfer an aggregate loss of approximately $13.4 million from accumulated other comprehensive income to pre-tax earnings as a loss during the next 12 months. The change in accumulated other comprehensive income (loss) related to derivatives was a gain of $99.1 million ($62.4 million after tax) compared to a loss of $61.9 million ($39.0 million after tax) for the three months ended March 31, 2006 and 2005, respectively. Additional volatility in earnings and other comprehensive income (loss) may occur in the future as a result of the application of FAS 133.

(6) SEGMENT INFORMATION

The Company applies Statement of Financial Accounting Standards 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 (E&P) segment are derived from the production and sale of natural gas and crude oil. Revenues for the Gas Distribution segment arise from the transportation and sale of natural gas at retail. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced gas volumes and through gathering fees associated with the transportation of natural gas to market. Gathering revenues have been insignificant to-date but are expected to increase in the future depending upon the level of production from our Fayetteville Shale area. In the Company’s Form 10-Q filed for the first quarter of 2005, capital expenditures and assets relating to gas gathering were included in the E&P segment. The March 31, 2005 capital expenditures and assets for the E&P segment reported in this Form 10-Q have been adjusted to exclude the gas gathering amounts. The gas gathering expenditures and assets are now included in the Midstream Services segment.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 to the financial statements in the Company's 2005 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes is the sum of operating income, interest expense, other income and minority interest in partnership. Other income in the Company’s consolidated statements of operations includes interest income. The "Other" column includes items not related to the Company's reportable segments including real estate, the Company’s investment in the Ozark Gas Transmission system and corporate items.

	Exploration And Production	Gas Distribution	Midstream Services	Other	Total
			(in thousands)		
Three months ended March 31, 2006:					
Revenues from external customers	$ 117,437	$ 78,211	$ 31,054	$ -	$ 226,702
Intersegment revenues	11,728	124	77,620	112	89,584
Operating income	80,779	7,907	1,070	48	89,804
Interest income [1]	2,293	15	-	-	2,308
Depreciation, depletion and amortization expense	26,247	1,597	233	26	28,103
Interest expense [1]	100	45	-	-	145
Provision for income taxes [1]	30,509	2,883	395	362	34,149
Assets	1,426,708	189,672	47,339	268,165 [2]	1,931,884 [2]
Capital expenditures[3]	154,907	3,494	4,769	3,375	166,545
Three months ended March 31, 2005:					
Revenues from external customers	$ 73,848	$ 62,658	$ 24,547	$ -	$ 161,053
Intersegment revenues	8,695	93	54,518	112	63,418
Operating income	47,731	7,447	1,037	11	56,226
Depreciation, depletion and amortization expense	18,514	1,699	10	24	20,247
Interest expense [1]	3,110	1,095	74	259	4,538
Provision (benefit) for income taxes [1]	16,482	2,353	356	(33)	19,158
Assets	960,869 [4]	169,357	27,041 [4]	42,992 [2]	1,200,259 [2]
Capital expenditures[3]	76,946 [4]	2,082	1,510 [4]	323	80,861

(1) Interest income, interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as debt and income tax expense (benefit) are incurred at the corporate level.
(2) Other assets include the Company's investment in cash equivalents, 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 include $9.6 million and $1.7 million for the three-month periods ended March 31, 2006 and 2005, respectively, relating to the change in accrued expenditures between periods.
(4) $1.5 million of assets and capital expenditures relating to gas gathering activities previously included in the Exploration and Production segment are now included in the Midstream Services segment.

Included in intersegment revenues of the Midstream Services segment are $63.5 million and $49.3 million for the first quarters of 2006 and 2005, respectively, for marketing of the Company's E&P sales. Intersegment sales by the E&P segment and Midstream Services segment to the Gas Distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures, prepaid debt costs and prepaid and intangible pension related costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

(7) INTEREST AND INCOME TAXES PAID

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

	For the three months ended March 31,	
	2006	2005
	(in thousands)	
Interest payments	$ 632	$ 886
Income tax payments	$ --	$ --

(8) CONTINGENCIES AND COMMITMENTS

At March 31, 2006, the Company was the sole guarantor of the principal and interest payments on NOARK's 7.15% Notes due 2018 which were issued in June 1998. The notes had principal outstanding of $39.0 million and require semi-annual payments of $0.6 million. The Company is required to fund the debt service for the notes to the extent they are not funded by the Company's share of the operations of the pipeline. The Company did not make any advances in the first quarters of 2006 and 2005.

On May 1, 2006, the Company entered into a Stock Purchase Agreement with Atlas Pipeline Partners, L.P. ("Atlas") whereby Atlas agreed to purchase the stock of Southwestern Energy Pipeline Company ("SWPL") for $69 million. The transaction closed on May 2, 2006. SWPL was a wholly-owned subsidiary of the Company and held the Company's 25% partnership interest in NOARK. As part of the transaction, the Company assumed the $39 million of debt obligations of NOARK Pipeline Finance, L.L.C., which the Company guaranteed as part of the financing of NOARK. The Company expects to recognize a pre-tax gain of approximately $10 million in the second quarter relating to the transaction.

The Company's Gas Distribution subsidiary has a transportation contract with Ozark Gas Transmission System for 66.9 MMcf per day of firm capacity that expires in 2014. Additionally, the Midstream Services segment has transportation contracts with Ozark Gas Transmission System for a total of 20.0 MMcf per day of firm capacity through 2006. Subsequent to March 31, 2006, the Midstream Services segment entered into an additional 3-year firm transportation agreement with the Ozark Gas Transmission System that requires total payments of $18.6 million of firm demand charges over the 3-year period.

The Company leases certain office space and equipment under non-cancelable operating leases expiring through 2013. Under certain of these leases the Company is required to pay property taxes, insurance, repairs and other costs related to the leased property. At March 31, 2006, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $2,710,000 in 2006, $3,481,000 in 2007, $3,122,000 in 2008, $2,996,000 in 2009, $2,480,000 in 2010 and $5,274,000 thereafter. Total rent expense for all operating leases was $512,000 for the first three months of 2006 and $325,000 for the comparable period of 2005.

The Company leases compressors related to its Midstream Services and E&P operations under non-cancelable operating leases expiring through 2011. At March 31, 2006, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $4,790,000 in 2006, $6,690,000 in 2007, $5,957,000 in 2008, $4,748,000 in 2009, $3,154,000 in 2010 and $1,793,000 thereafter.

The Company's Gas Distribution segment has entered into various non-cancelable agreements related to demand charges for the transportation and purchase of natural gas with third parties. These costs are recoverable from the utility's end-use customers. At March 31, 2006, future payments under these non-cancelable demand contracts are $6,840,000 in 2006, $8,833,000 in 2007, $9,195,000 in 2008, $9,582,000 in 2009, $9,969,000 in 2010 and $41,660,000 thereafter. Additionally, our E&P and Midstream Services segments have a commitment to a third party for demand transportation charges. At March 31, 2006, future payments under these non-cancelable demand contracts are $3,024,000 in 2006, $725,000 in 2007, $617,000 in 2008, $617,000 in 2009, $411,000 in 2010 and $0 thereafter.

In 2005, we entered into agreements to fabricate ten new land drilling rigs. Additionally, in the first quarter of 2006, we entered into an agreement to fabricate two surface rigs. Including change orders, ancillary equipment and supplies, the total cost of these twelve rigs is approximately $105.5 million. As of March 31, 2006, payments made under these agreements were $56.7 million with the remainder to be due in 2006.

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

A lawsuit was filed against the Company in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure' prospect in Louisiana. The allegations were contested and, in 2002, the Company was granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying the Company's motion for summary judgment and granting the motion for summary judgment of the other party. The Company's motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, the Company filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas Supreme Court invited additional briefing by the parties. In March of 2006, the Texas Supreme Court requested that both parties submit full briefs on the merits of the case. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, the Company could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by the Company and its legal counsel, no accrual for loss is currently recorded.

(9) STOCK-BASED COMPENSATION

On January 1, 2006, the Company adopted FAS 123(R), which requires companies to measure the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The Company has elected to use the modified prospective application method such that FAS 123(R) applies to new awards, the unvested portion of existing awards and to awards modified, repurchased or canceled after the effective date. The Company has equity incentive plans that provide for the issuance of stock options and restricted stock. These plans are discussed more fully in the Company's Form 10-K for the year ended December 31, 2005. All options are issued at fair market value at the date of grant and expire seven years from the date of grant for awards under the 2004 Plan and ten years from the date of grant for awards under all other plans. Generally, stock options granted to employees and directors vest ratably over three to four years from the grant date. No new stock options have been granted subsequent to January 1, 2006. The Company issues shares of restricted stock to employees and directors which generally vest over four-years. The Company recognizes stock-based compensation expense on a straight-line basis over the requisite service period of the individual grants with the exception of awards granted to participants who have reached retirement age or will reach retirement age during the vesting period. In the fourth quarter of 2005, the Board of Directors prospectively revised the vesting for restricted stock and stock options granted to participants on or after December 8, 2005 under the 2004 Stock Incentive Plan to immediately accelerate the vesting upon death, disability or retirement (subject to a minimum of five years of service). This change did not affect awards issued prior to December 8, 2005.

Prior to January 1, 2006, the Company accounted for its long-term equity incentive plans under the intrinsic value method described in APB Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretation. The Company, applying the intrinsic value method, did not record stock-based compensation cost for stock options because the exercise price of the stock options equaled the market price of the underlying stock at the date of grant.

For the three months ended March 31, 2006, the Company recognized compensation costs of $670,000 related to stock options issued prior to January 1, 2006. Of this amount, $127,000 was directly related to the acquisition, exploration and development activities for the Company's gas and oil properties and was capitalized into the full cost pool. The remaining costs were recorded in general and administrative expenses. Accordingly, the Company recorded a deferred tax benefit of $176,000. A total of $4,835,000 of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on exercise of stock options, post vesting forfeitures and other factors to estimate the expected term of the share-based payments granted. The risk free rate is based on the U.S. Treasury yield curve in effect at the time of grant.

Assumptions	2005
Risk-free interest rate	4.4%
Expected dividend yield	—
Expected volatility	40.6%
Expected term	4 years

The Company currently utilizes treasury shares when a stock option is exercised or when restricted stock is granted. The Company intends to utilize authorized but unissued shares after the remaining treasury shares are issued.

For the three months ended March 31, 2006, $457,000 relating to grants of restricted stock prior to January 1, 2006 was recorded in general and administrative expenses with an additional $299,000 capitalized into the full cost pool.

The following table illustrates the effect on net income and earnings per share in the comparable quarter of the prior year as if the fair value based method under FASB Statement 123 had been applied to all outstanding vested and unvested awards in that period.

	For the three months ended March 31, 2005 (in thousands, except per share)
Net Income, as reported	$ 32,621
Add back: Stock option based compensation expense included in reported net income, net of related tax effects	403
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(813)
Pro forma net income	$ 32,211
Earnings per share:	
Basic-as reported	$ 0.23
Basic-pro forma	$ 0.23
Diluted-as reported	$ 0.22
Diluted-pro forma	$ 0.22

The following tables summarize stock option activity for the first quarter of 2006 and provides information for options outstanding at March 31, 2006:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2005	7,126,465	$ 4.34		
Granted	—	—		
Exercised	401,338	3.05		
Forfeited or expired	2,826	12.45		
Outstanding at March 31, 2006	6,722,301	$ 4.41	5.1	$ 186,758
Exercisable at March 31, 2006	5,809,296	$ 2.73	4.8	$ 171,144

There were no options granted during the first three-months of 2006 and 2005. The total intrinsic value of options exercised during the first three-months of 2006 and 2005 was $10.9 million and $2.4 million, respectively.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at March 31,2006	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at March 31,2006	Weighted Average Exercise Price
$1.50 - $1.86	2,988,960	$ 1.75	4.1	2,988,960	$ 1.75
$1.87 - $2.85	762,708	2.53	5.0	762,708	2.53
$2.86 - $5.00	1,433,876	2.99	5.0	1,393,876	2.99
$5.01 - $12.00	882,820	5.55	7.7	534,778	5.45
$12.01 - $36.00	653,937	20.32	6.0	128,974	12.45
	6,722,301	$ 4.41	5.1	5,809,296	$ 2.73

The following table summarizes restricted stock award activity for the first quarter of 2006 and provides information for unvested restricted stock awards outstanding at March 31, 2006.

	Number of Nonvested Shares	Weighted Average Grant Date Fair Value
Nonvested shares at December 31, 2005	707,142	$ 11.13
Granted	13,450	33.64
Vested	(7,800)	6.00
Forfeited	(13,363)	9.77
Nonvested shares at March 31, 2006	699,429	$ 11.65

As of March 31, 2006, there was $7.4 million of total unrecognized compensation cost related to nonvested shares. That cost is expected to be recognized over a weighted-average period of 1.4 years. The total fair value of shares vested during the first three months of 2006 and 2005 was $47,000 and $58,000, respectively.

Associated with the exercise of stock options, the Company received a tax benefit of $2.6 million and $0.3 million in the first three months of 2006 and 2005, respectively. The tax benefit is recorded as an increase in additional paid-in capital.

(10) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. Net periodic pension and other postretirement benefit costs include the following components for the three-month periods ended March 31, 2006 and 2005:

	Pension Benefits	
	For the three months ended March 31,	
	2006	2005
	(in thousands)	
Service cost	$ 752	$ 631
Interest cost	970	941
Expected return on plan assets	(1,144)	(1,194)
Amortization of prior service cost	109	110
Amortization of net loss	190	81
Net periodic benefit cost	$ 877	$ 569

	Postretirement Benefits	
	For the three months ended March 31,	
	2006	2005
	(in thousands)	
Service cost	$ 68	$ 43
Interest cost	47	50
Expected return on plan assets	(17)	(14)
Amortization of net loss	8	10
Amortization of transition obligation	22	22
Net periodic benefit cost	$ 128	$ 111

We currently expect to contribute $3.5 million to our pension plans and $0.4 million to our postretirement benefit plans in 2006, which is the same as our original estimates as of December 31, 2005. As of March 31, 2006, there have been no contributions made to our pension plans, and $0.1 million has been contributed to our postretirement benefit plans.

(11) ASSET RETIREMENT OBLIGATIONS

Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," (FAS 143) was adopted by the Company on January 1, 2003. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Company owns natural gas and oil properties which require expenditures to plug and abandon the wells when reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period the liability is incurred (at the time the wells are drilled or acquired). The following table summarizes the Company's activity related to asset retirement obligations for the three month period ended March 31, 2006 and for the year ended December 31, 2005:

	2006	2005
	(in thousands)	
Asset retirement obligation at January 1	$ 9,229	$ 8,565
Accretion of discount	93	326
Obligations incurred	147	436
Obligations settled/removed	(12)	(1,553)
Revisions of estimates	-	1,455
Asset retirement obligation at March 31, 2006 and December 31, 2005	$ 9,457	$ 9,229
Current liability	419	358
Long-term liability	9,038	8,871
Asset retirement obligation at March 31, 2006 and December 31, 2005	$ 9,457	$ 9,229

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

The following updates information as to Southwestern Energy Company's financial condition provided in our 2005 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three-month periods ended March 31, 2006 and 2005. For definitions of commonly used gas and oil terms used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2005 Annual Report on Form 10-K.

This Form 10-Q contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in Item 1A, "Risk Factors" and elsewhere in our 2005 Annual Report on Form 10-K and Item 1A, “Risk Factors” in this Form 10-Q. You should read the following discussion with our financial statements and related notes included in this Form 10-Q. Historical per share information provided as of March 31, 2005 in the financial statements, footnotes and Management’s Discussion and Analysis of Financial Condition and Results of Operations has been adjusted to reflect the two-for-one stock splits effected on June 3, 2005 and November 17, 2005.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil within the United States, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas distribution, marketing and transportation businesses and our expanding gathering activities. Our marketing and our gas gathering businesses are collectively referred to as our Midstream Services. We operate principally in three segments: Exploration and Production (or E&P), Natural Gas Distribution and Midstream Services.

We currently derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. There has been significant price volatility in the natural gas and crude oil market in recent years due to a variety of factors we cannot control or predict. These factors, which include weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas. In addition, the price we realize for our gas production is affected by our hedging activities as well as locational differences in market prices. Our ability to increase our natural gas production is dependent upon our ability to economically find and produce natural gas, our ability to control costs, and our ability to market natural gas on economically attractive terms to our customers. For the three months ended March 31, 2006, 90% of our operating income was generated by our E&P segment, 9% by our Natural Gas Distribution segment, and 1% by our Midstream segment as compared to 85%, 13% and 2%, respectively, for the comparable period in 2005.

Our revenues for the first quarter of 2006 were approximately 41% higher than the comparable period in 2005 due to increased production volumes and higher market-driven commodity prices received for our gas and oil sales. We reported net income of $58.4 million, or $0.34 per share on a diluted basis, on revenues of $226.7 million for the three months ended March 31, 2006, up from $32.6 million, or $0.22 per diluted share, on revenues of $161.1 million for the same period in 2005. Operating income for our E&P segment was $80.8 million for the quarter ended March 31, 2006, up from $47.7 million for the same period in 2005. The increases in our net income and in the operating income for the E&P segment were primarily due to a 14% increase in production volumes and higher realized natural gas and oil prices, which were partially offset by an increase in our operating costs and expenses. Operating income from our Gas Distribution segment was $7.9 million for the three months ended March 31, 2006, compared to $7.4 million for the same period in 2005. The increase in operating income for our gas distribution segment resulted primarily from a $4.6 million annual rate increase effective October 31, 2005. Operating income for our Midstream Services segment was $1.1 million for the first quarter of 2006, compared to $1.0 million for the first quarter of 2005.

Our natural gas production has increasingly generated a substantial portion of our total operating revenues as a result of the natural gas focus of our capital investments in the past three years. Sales of natural gas production accounted for 90% of total operating revenues for the E&P segment for the first quarters of 2006 and 2005.

In the first quarter of 2006, our gas and oil production increased to 15.9 Bcfe, up from 14.0 Bcfe in the first quarter of 2005. The increase in 2006 production primarily resulted from an increase in production from our Overton Field in East Texas and increased production in the Arkoma Basin, primarily related to our Fayetteville Shale play.

Our capital investments totaled $166.5 million for the first quarter of 2006, up from $80.9 million in the first quarter of 2005. We invested $154.9 million in our E&P segment in the first quarter of 2006, compared to $76.9 million for the same period in 2005.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended March 31,	
	2006	2005
Revenues (in thousands)	$129,165	$82,543
Operating income (in thousands)	$80,779	$47,731
Gas production (MMcf)	14,836	13,019
Oil production (MBbls)	177	161
Total production (MMcfe)	15,896	13,987
Average gas price per Mcf, including hedges	$7.86	$5.71
Average gas price per Mcf, excluding hedges	$7.60	$5.72
Average oil price per Bbl, including hedges	$56.80	$37.87
Average oil price per Bbl, excluding hedges	$60.63	$47.54
Average unit costs per Mcfe		
Lease operating expenses	$0.53	$0.45
General & administrative expenses	$0.53	$0.39
Taxes, other than income taxes	$0.33	$0.33
Full cost pool amortization	$1.59	$1.29

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up 56% to $129.2 million for the three months ended March 31, 2006, as compared to $82.5 million for the same period in 2005. The increase was primarily due to increased production volumes and higher gas and oil prices realized for our production. Revenues for the first three months of 2006 and 2005 also include pre-tax gains of $1.9 million and $2.1 million, respectively, related to the sale of gas in storage inventory.

Operating Income. Operating income for the E&P segment was up 69% to $80.8 million for the first quarter of 2006, compared to $47.7 million for the same period in 2005. The increase in operating income resulted from the increase in revenues, as discussed above, partially offset by increased operating costs and expenses.

Production. Gas and oil production during the first quarter of 2006 was 15.9 Bcfe, up 14% from 14.0 Bcfe in the first quarter of 2005. The comparative increase in production primarily resulted from an increase in production from our Overton Field in East Texas and increased production in the Arkoma Basin, primarily related to our Fayetteville Shale play. Gas production was 14.8 Bcf for the first quarter of 2006 up from 13.0 Bcf for the first quarter of 2005. Intersegment sales to our gas distribution systems were 1.2 Bcf during the three months ended March 31, 2006, compared to 1.4 Bcf for the same period in 2005. Our oil production was 177 thousand barrels (MBbls) during the first quarter of 2006, up from 161 MBbls for the same period of 2005.

Commodity Prices

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials (we refer you to Item 3 of this Form 10-Q for additional discussion). The average price realized for our gas production, including the effect of hedges, was $7.86 per thousand cubic feet (Mcf) for the three months ended March 31, 2006, up from $5.71 per Mcf for the same period of 2005. The change in the average price realized primarily reflects changes in average spot market prices and the effects of our price hedging activities. Our hedging activities increased our average gas price $0.26 per Mcf during the first three months of 2006, compared to a minimal impact during the same period of 2005. Locational differences in market prices for natural gas have continued to be wider than historically experienced. We had protected approximately 95% of our production in the first quarter of 2006 from the impact of basis differentials. Through our hedging activities and sales arrangements, for the remainder of 2006, we have protected approximately 65% of our anticipated gas production from the impact of basis differentials. Disregarding the impact of hedges, the average price received for our gas production during the first quarter of 2006 was approximately $1.35 lower than average NYMEX spot prices. For the remainder of 2006, we have hedges in place for 36.7 Bcf of gas production and for 2007 and 2008 we have 40.0 Bcf and 8.0 Bcf, respectively, of our future gas production hedged. Additionally, we have basis hedges on 20.0 Bcf for the remainder of 2006 and 10.0 Bcf for 2007 in order to partially reduce the effect of market differentials on prices we receive.

We realized an average price of $56.80 per barrel for our oil production, including the effect of hedges, during the three months ended March 31, 2006, up from $37.87 per barrel for the same period of 2005. The average price we received for our oil production in the first three months of 2006 and 2005 was reduced by $3.83 per barrel and $9.67 per barrel, respectively, due to the effects of our hedging activities. For the remainder of 2006, we have hedged 90,000 barrels of our oil production at an average NYMEX price of $37.30 per barrel.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.53 for the first quarter of 2006, compared to $0.45 for the same period in 2005. The increase in lease operating expenses per Mcfe in 2006 resulted primarily from increases in gathering and compression costs.

General and administrative expenses per Mcfe were $0.53 for the first quarter of 2006, compared to $0.39 for the same period in 2005. General and administrative expenses for our E&P segment increased to $8.5 million for the first quarter of 2006, compared to $5.4 million for the same period of 2005 due primarily to increased compensation and other costs associated with increased staffing levels.

Taxes other than income taxes per Mcfe were $0.33 for the first quarters of 2006 and 2005 as the effects of higher gas and oil prices were offset by the changing mix of production and tax exemptions related to portions of our Overton Field production.

Our full cost pool amortization rate averaged $1.59 per Mcfe for the first three months of 2006, compared to $1.29 for the same period in 2005. The amortization rate is impacted by reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, and the level of unevaluated costs excluded from amortization. Although we expect our amortization rate to continue to increase in the near term as a result of increased costs in finding and developing gas and oil reserves, we cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as the uncertainty of the future success of our Fayetteville Shale play. Unevaluated costs excluded from amortization were $131.1 million at March 31, 2006, compared to $56.6 million at March 31, 2005. The increase in unevaluated costs since March 31, 2005 resulted primarily from an increase in our undeveloped leasehold acreage related to our Fayetteville Shale play and increased drilling activity.

We utilize the full cost method of accounting for costs related to the exploration, development, and acquisition of oil and natural gas reserves. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities, are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. At March 31, 2006 and 2005, our unamortized costs of natural gas and oil properties did not exceed the ceiling amount. At March 31, 2006, our standardized measure was calculated based upon quoted market prices of $7.18 per Mcf for Henry Hub gas and $66.63 per barrel for West Texas Intermediate oil, adjusted for market differentials. A significant decline in natural gas and oil prices from March 31, 2006 levels as well as changes in production rates, levels of reserves and the evaluation of costs excluded from amortization, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

Natural Gas Distribution

	For the three months ended March 31,	
	2006	2005
Revenues (in thousands)	$78,335	$62,751
Gas purchases (in thousands)	$56,505	$42,495
Operating costs and expenses (in thousands)	$13,923	$12,809
Operating income (in thousands)	$7,907	$7,447
Deliveries (Bcf)		
Sales and end-use transportation	8.3	9.2
Sales customers at period-end	149,486	146,684
Average sales rate per Mcf	$13.11	$9.16
Heating weather - degree days	1,787	1,902
Percent of normal	82%	89%

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-month period ended March 31, 2006 increased 25% from the comparable period of 2005 due primarily to higher average sales rates resulting from higher gas prices and the effects of a $4.6 million annual rate increase effective October 31, 2005.

Operating income for our gas distribution segment increased $0.5 million in the first quarter of 2006, as compared to the same period of 2005, due primarily to the effects of the rate increase, which was partially offset by increased operating costs and expenses. Weather during the first three months of 2006 was 18% warmer than normal and 7% warmer than the same period in 2005.

Deliveries and Rates

In the first quarter of 2006, Arkansas Western sold 5.8 Bcf to its customers at an average rate of $13.11 per Mcf, compared to 6.6 Bcf at $9.16 per Mcf in the first quarter of 2005. Additionally, Arkansas Western transported 2.5 Bcf in the three month period ended March 31, 2006 compared to 2.6 Bcf in the same period of 2005 for its end-use customers. The decrease in volumes sold during the first three months of 2006 was due primarily to variations in weather and customer conservation brought about by high gas prices in recent years.

Our utility's tariffs contain a weather normalization clause intended to lessen the impacts of revenue increases and decreases that might result from weather variations during the winter heating season. The increase in gas costs in the first three months of 2006 was reflected in the utility segment's average rate for its sales. The fluctuations in the average sales rate primarily reflect changes in the average cost of gas purchased for delivery to our customers, which are passed through to customers under automatic adjustment clauses.

Our utility segment hedged 1.8 Bcf of gas purchases in the first three months of 2006 which had the effect of increasing its total gas supply cost by $6.8 million. In the first three months of 2005, our utility hedged 2.9 Bcf of its gas supply which increased its total gas supply cost by $1.4 million. Additionally, our utility segment currently has hedges in place on 0.2 Bcf of gas purchases at an average purchase price of $9.79 per Mcf for the 2006-2007 winter season. See Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

Operating Costs and Expenses

The changes in purchased gas costs for our gas distribution segment reflect volumes purchased, prices paid for supplies and the mix of purchases from various gas supply contracts (base load, swing and no-notice). Other operating costs and expenses for this segment during the first quarter were higher than the comparable period of the prior year due primarily to higher general and administrative expenses and higher transmission expenses. The increase in general and administrative expense primarily resulted from increased compensation costs, and the increase in transmission expense is a direct result of increased natural gas prices.

Midstream Services

	For the three months ended March 31,	
	2006	2005
Revenues (in thousands)	$108,674	$79,065
Gas purchases (in thousands)	$105,533	$77,716
Operating income (in thousands)	$1,070	$1,037
Gas volumes marketed (Bcf)	13.8	14.4

Our operating income from Midstream Services was $1.1 million on revenues of $108.7 million in the first quarter of 2006, compared to $1.0 million on revenues of $79.1 million for the same period of 2005. The increase in revenues is attributable to an increase in natural gas commodity prices partially offset by a decrease in volumes marketed. The increase in revenues was largely offset by a comparable increase in purchased gas costs. Operating income from natural gas marketing fluctuates depending on the margin we are able to generate between the purchase of the commodity and the ultimate disposition of the commodity. We marketed 9.7 Bcf of affiliated gas in the first quarter of 2006, representing 70% of total volumes marketed, compared to 10.8 Bcf, or 75% of total volumes marketed, for the same period in 2005. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to Item 3, "Qualitative and Quantitative Disclosure about Market Risks" in this Form 10-Q for additional information.

Midstream Services also had gathering revenues of $0.6 million in the first quarter of 2006 related to gathering systems it owns in Arkansas. Gathering revenues and expenses for this segment are expected to continue to grow in the future as gathering systems supporting our Fayetteville Shale play are constructed.

Transportation

We recorded pre-tax income of $0.9 million from operations related to our investment in the NOARK Pipeline System Limited Partnership (NOARK) for the first quarter of 2006, compared to $0.1 million for the first quarter of 2005. These amounts were recorded in other income in our statements of operations.

Other Revenues

Other revenues for the first three months of 2006 and 2005 included pre-tax gains of $1.9 million and $2.1 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, were insignificant for the first quarter of 2006, as compared to the same period of 2005. Interest costs in the first quarter of 2006 decreased because we have no outstanding debt under our revolving debt facility and we paid $125 million in principal amount for notes due upon their maturity in December 2005 using funds from our equity offering in September 2005. Interest capitalized increased to $2.4 million in the first quarter of 2006 as compared to $0.7 million for the same period in 2005. The increase in capitalized interest is primarily due to the level of investment in unevaluated properties in our E&P segment and the capitalization of interest during the construction phase of our drilling rigs. Costs excluded from amortization in the E&P segment increased to $131.1 million at March 31, 2006, compared to $56.6 million at March 31, 2005. In the first three months of 2006, total capital expenditures for our E&P segment were $154.9 million, up from $76.9 million for the same period in 2005.

During the first quarter of 2006, we earned interest income of $2.3 million related to our cash investments. This amount is recorded in other income.

Income Taxes

Our provision for deferred income taxes was an effective rate of 36.9% for the three months ended March 31, 2006 and 37.0% for the three months ended March 31, 2005. The changes in the provision for deferred income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences.

Pension Expense

We recorded expenses of $1.0 million in the first quarter of 2006 for our pension and other postretirement benefit plans, compared to $0.7 million in the first quarter of 2005. The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $3.9 million to our pension and other postretirement plans in 2006. As of March 31, 2006, no contributions have been made to our pension plans and $0.1 million has been contributed to our other postretirement plans. For further information regarding our pension plans, we refer you to Note 10 of the financial statements in this Form 10-Q.

Stock-Based Compensation

As of January 1, 2006, we adopted Statement of Financial Accounting Standards No.123(R), Share-Based Payment, (FAS 123(R)), which requires companies to recognize in the statement of operations the grant-date fair value of stock awards issued to employees and directors. We adopted FAS 123(R) using the modified prospective transition method. In accordance with the modified prospective transition method, our Consolidated Financial Statements for prior periods have not been restated to reflect the impact of FAS 123(R). As a result of applying FAS 123(R), we recognized an expense of $1.0 million and capitalized $0.4 million to the full cost pool for the first quarter of 2006. In the first quarter of 2005, we expensed $0.4 million and capitalized $0.3 million for the amortization of restricted stock grants. We refer you to Note 9 of the financial statements in this Form 10-Q for additional discussion of our equity based compensation plans and our adoption of FAS 123(R).

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds, our unsecured revolving credit facility (discussed below under "Financing Requirements") and funds accessed through public debt and equity markets as our primary sources of liquidity. We may borrow up to $500 million under our revolving credit facility from time to time. As of March 31, 2006 and December 31, 2005, we had no indebtedness outstanding under our revolving credit facility. During 2006, we expect to draw on a portion of the funds available under our credit facility to fund our planned capital expenditures (discussed below under "Capital Expenditures"), which are expected to exceed the net cash generated by our operations and cash investments.

Net cash provided by operating activities was $143.4 million in the first three months of 2006, compared to $103.1 million for the same period of 2005. The primary components of cash provided from operations are net income adjusted for depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. Cash from operating activities increased in the first quarter of 2006 due mainly to increased net income and the related increase in deferred income taxes generated by our E&P segment. For the first three months of 2006 and 2005, cash provided by operating activities provided 86% and 100% of our requirements for capital expenditures, respectively.

We believe that our operating cash flow, remaining funds from our 2005 equity offering and our credit facility will be adequate to meet our capital and operating requirements for 2006. We may choose to refinance certain portions of our borrowings by issuing long-term debt in the public or private debt markets.

Our cash flow from operating activities is highly dependent upon market prices that we receive for our gas and oil production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 5 to the financial statements included in this Form 10-Q and Item 3, "Quantitative and Qualitative Disclosures about Market Risks." Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon cash flow available.

Capital Expenditures

Our capital expenditures for the first three months of 2006 were $166.5 million, compared to $80.9 million for the same period in 2005. In the first quarter of 2006 and 2005, capital expenditures for our E&P segment were $154.9 million (including $9.6 million relating to accrued expenditures) and $76.9 million (including $1.7 million relating to the change in the amount of accrued expenditures), respectively. Our capital investments for calendar year 2006 are planned to be $830.1 million, including $770.3 million in our E&P segment. Our 2006 capital investment program is expected to be funded through cash flow from operations, the remaining net proceeds from our equity offering, and borrowings under our revolving credit facility. We may adjust our level of 2006 capital investments dependent upon our level of cash flow generated from operations and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $100.0 million at March 31, 2006 and at December 31, 2005. We have a $500 million revolving credit facility that expires in January 2010. At March 31, 2006 and December 31, 2005, we had no outstanding debt under our revolving credit facility. The interest rate on the facility is calculated based upon our public debt rating and is currently 125 basis points over LIBOR. Our publicly traded notes were downgraded in January 2005 by Standard and Poor’s to BBB- from BBB, and continue to be rated Ba2 by Moody’s. Any future downgrades in our public debt ratings could increase the cost of funds under our revolving credit facility.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreement, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of shareholders’ equity, and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Additionally, there are certain limitations on the amount of indebtedness that may be incurred by our subsidiaries. We were in compliance with all of the covenants of our credit agreement at March 31, 2006. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our credit facility, we would have to decrease our capital expenditure plans.

At March 31, 2006, our capital structure consisted of 7% debt (excluding our guarantee of NOARK's obligations) and 93% equity, with a ratio of EBITDA to interest expense of 36.1. EBITDA is a measure required by our credit facility financial covenants and is defined as net income plus interest expense, income tax expense, and depreciation, depletion and amortization. Shareholders' equity in the March 31, 2006 balance sheet includes an accumulated other comprehensive loss of $37.4 million related to our hedging activities that is required to be recorded under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). This amount is based on current market values of our hedges at March 31, 2006, and does not necessarily reflect the value that we will receive or pay when the hedges ultimately are settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our credit facility's financial covenants with respect to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 as well as the non-cash impact of any full cost ceiling write-downs, and include the guarantee of NOARK's obligations. Our capital structure, including our guarantee of NOARK's obligations of $39.0 million, would be 10% debt and 90% equity at March 31, 2006, without consideration of the accumulated other comprehensive loss related to FAS 133 of $37.4 million.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 70% to 75% of our expected 2006 gas production and 15% to 20% of our expected 2006 oil production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital expenditure plans. If commodity prices remain at or near 2005 levels throughout 2006 and our capital expenditure plans do not change, we will increase our long-term debt in 2006. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital expenditures.

Off-Balance Sheet Arrangements

At March 31, 2006, we held a 25% general partnership interest in NOARK, which owns the Ozark Gas Transmission System that is utilized to transport our gas production and the gas production of others. We accounted for our investment under the equity method of accounting. As a result of the sale by Enogex of its interests in NOARK and the related prepayment of its portion of NOARK's 7.15% Notes due 2018, we were the sole guarantor of the outstanding notes. At March 31, 2006, the outstanding principal amount of these notes was $39.0 million and requires semi-annual principal payments of $0.6 million. Under the guarantee, we were required to fund the notes to the extent that they are not funded by our share of the operations of the pipeline. We did not advance funds to NOARK in 2005 or in the first three months of 2006. We did not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

On May 1, 2006, we entered into a Stock Purchase Agreement with Atlas Pipeline Partners, L.P. ("Atlas") whereby Atlas agreed to purchase the stock of Southwestern Energy Pipeline Company ("SWPL") for $69 million. The transaction closed on May 2, 2006. SWPL was a wholly-owned subsidiary of the Company and held the Company's 25% partnership interest in NOARK. As part of the transaction, we assumed the $39 million of debt obligations of NOARK Pipeline Finance, L.L.C., which we guaranteed as part of the financing of NOARK. We expect to recognize a pre-tax gain of approximately $10 million in the second quarter relating to the transaction.

Our share of the results of operations included in other income related to our NOARK investment was pre-tax income of $0.9 million and $0.1 million for the first quarter of 2006 and 2005, respectively.

The increase in pre-tax income in 2006 was primarily due to increased throughput and higher average rates charged to customers.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations at March 31, 2006 were as follows:

***Contractual Obligations*:**

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
	(in thousands)				
Long-term debt	$ 100,000	$ —	$ 60,000	$ —	$ 40,000
Interest on senior notes[1]	47,293	7,459	14,918	6,162	18,754
Operating leases[2]	20,063	3,595	6,505	5,318	4,645
Unconditional purchase obligations[3]	—	—	—	—	—
Operating agreements[4]	22,094	22,094	—	—	—
Rental compression[5]	27,132	6,486	12,328	7,266	1,052
Demand charges[6]	91,473	12,314	19,453	20,618	39,088
Drilling rigs[7]	48,834	48,834	—	—	—
Other obligations[8]	13,662	13,041	621	—	—
	$ 370,551	$113,823	$113,825	$ 39,364	$103,539

(1) Interest on the senior notes includes interest through 2009 on the $60 million notes that are due in 2027 and putable at the holder's option in 2009.

(2) We lease certain office space and equipment under non-cancelable operating leases expiring through 2013.

(3) Our Gas Distribution segment has volumetric commitments for the purchase of gas under non-cancelable competitive bid packages and non-cancelable wellhead contracts. Volumetric purchase commitments at March 31, 2006 totaled 0.7 Bcf, comprised of 0.4 Bcf in less than one year, 0.2 Bcf in one to three years and 0.1 Bcf in three to five years. Our volumetric purchase commitments are priced primarily at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers.

(4) Our E&P segment has commitments for up to $22.1 million in termination fees related to rig operator agreements in the event that the agreements are terminated.

(5) Our E&P and Midstream Services segments have commitments for approximately $27.1 million of compressor rental fees associated primarily with our Overton operations and our Fayetteville Shale play.

(6) Our Gas Distribution segment has commitments for approximately $86.1 million of demand charges on non-cancelable firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers. Our E&P segment has commitments for approximately $4.3 million of demand transportation charges, and our Midstream Services segment has commitments for approximately $1.1 million of demand transportation charges.

(7) Our E&P segment has commitments related to the purchase of twelve drilling rigs expected to be delivered within 2006 for approximately $48.8 million, including ancillary equipment.

(8) Our other significant contractual obligations include approximately $5.6 million related to seismic services, approximately $3.8 million for funding of benefit plans, $1.4 million in land leases, and approximately $1.0 million for various information technology support and data subscription agreements.

In 2005, we entered into agreements to fabricate ten new land drilling rigs. Additionally, in the first quarter of 2006, we entered into an agreement to fabricate two surface rigs. Including change orders, ancillary equipment and supplies, the total cost of these twelve rigs is approximately $105.5 million. As of March 31, 2006, payments made under these agreements were $56.7 million with the remainder to be due in 2006.

Subsequent to March 31, 2006, the Midstream Services segment entered into an additional 3-year firm transportation agreement with the Ozark Gas Transmission System that requires total payments of $18.6 million of firm demand charges over the 3-year period.

On May 1, 2006, we entered into a Stock Purchase Agreement with Atlas Pipeline Partners, L.P. ("Atlas") whereby Atlas agreed to purchase the stock of Southwestern Energy Pipeline Company ("SWPL") for $69 million. The transaction closed on May 2, 2006. As part of the transaction, we assumed the $39 million of debt obligations of NOARK Pipeline Finance, L.L.C., which we guaranteed as part of the financing of NOARK.

Contingent Liabilities and Commitments

We have the following commitments and contingencies that could create, increase or accelerate our liabilities. Substantially all of our employees are covered by defined benefit and postretirement benefit plans. As a result of actuarial data, we expect to record expenses of $4.0 million in 2006 for these plans, of which $1.0 million has been recorded in the first three months of 2006. At March 31, 2006, we recorded an accrued pension benefit liability of $8.8 million. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 10 of the financial statements in this Form 10-Q.

As discussed above in "Off-Balance Sheet Arrangements," we are the sole guarantor of the principal and interest payments on NOARK's 7.15% Notes due 2018. At March 31, 2006, the outstanding principal of these notes was $39.0 million. The notes require semi-annual principal payments of $0.6 million.

We are subject to litigation and claims that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. A lawsuit was filed against us in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company’s Boure' prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. Our motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, we filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas Supreme Court invited additional briefing by the parties. In March of 2006, the Texas Supreme Court requested that both parties submit full briefs on the merits of the case. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by us and our legal counsel, no accrual for loss is currently recorded.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our credit facility described above. We had positive working capital of $168.3 million at March 31, 2006 and $158.7 million at December 31, 2005. Current assets included $210.7 million of remaining proceeds from our 2005 equity offering that is invested in cash investments. Current liabilities decreased $92.7 million, due primarily to a decrease in our current hedging liability and accounts payable accruals at March 31, 2006.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 7.6 Bcf at $3.45 at March 31, 2006 and 8.5 Bcf at $3.78 at December 31, 2005.

The gas in inventory for the E&P segment is used primarily to supplement field production in meeting the segment's contractual commitments including delivery to customers of our gas distribution business, especially during periods of colder weather. As a result, demand fees paid by the gas distribution segment to the E&P segment, which are passed through to the utility's customers, are a part of the realized price of the gas in storage. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. A significant decline in the future market price of natural gas could result in a write down of our gas in storage carrying cost.

FORWARD-LOOKING INFORMATION

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

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

* the timing and extent of changes in commodity prices for natural gas and oil;
* the timing and extent of our success in discovering, developing, producing and estimating reserves;
* the extent to which the Fayetteville Shale play can replicate the results of other productive shale gas plays;
* the potential for significant variability in reservoir characteristics of the Fayetteville Shale over such a large acreage position;
* the extent of our success in drilling and completing horizontal wells;
* our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
* our lack of experience owning and operating drilling rigs;
* our ability to fund our planned capital expenditures;
* our future property acquisition or divestiture activities;
* the effects of weather and regulation on our gas distribution segment;
* increased competition;
* the impact of federal, state and local government regulation;

* the financial impact of accounting regulations and critical accounting policies;
* changing market conditions and prices (including regional basis differentials);
* the comparative cost of alternative fuels;
* conditions in capital markets and changes in interest rates;
* the availability of oil field personnel, services, drilling rigs and other equipment; and
* any other factors listed in the reports we have filed and may file with the SEC.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in our 2005 Annual Report on Form 10-K and this Form 10-Q.

Should one or more of the risks or uncertainties described above or elsewhere in our 2005 Annual Report on Form 10-K or this Form 10-Q occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our 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 Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounts for greater than 4% of accounts receivable at March 31, 2006. In addition, please see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At March 31, 2006, we have $100.0 million of debt with a fixed interest rate of 7.46%. Our $500 million revolving credit facility has a floating interest rate, and at March 31, 2006, we had no borrowings outstanding under the facility. Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate. We do not have any interest rate swaps in effect currently.

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production, to hedge activity in our marketing segment, and to hedge the purchase of gas in our utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX (New York Mercantile Exchange) futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which we pay to (production hedge) or receive from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

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

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for our gas and oil production, gas purchases and marketing activities. The table presents the notional amount in Bcf (billion cubic feet) and MBbls (thousand barrels), the weighted average contract prices, and the fair value by expected maturity dates. At March 31, 2006, the fair value of these financial instruments was a $57.0 million liability.

	Expected Maturity Date		
	2006	2007	2008
Production and Marketing			
Natural Gas			
Swaps with a fixed price receipt			
Contract Volume (Bcf)	5.7	12.0	-
Weighted average price per Mcf	$6.21	$6.62	-
Fair value (in millions)	($9.3)	($31.2)	-
Price collars			
Contract volume (Bcf)	30.5	28.0	8.0
Weighted average floor price per Mcf	$5.34	$6.64	$7.72
Fair value of floor (in millions)	$2.8	$8.8	$6.1
Weighted average ceiling price per Mcf	$8.38	$11.91	$15.11
Fair value of ceiling (in millions)	($21.6)	($17.5)	($5.2)
Swaps with a fixed price payment			
Contract volume (Bcf)	0.5	-	-
Weighted average price per Mcf	$8.42	-	-
Fair value (in millions)	$0.6	-	-
Oil			
Swaps with a fixed price receipt			
Contract volume (MBbls)	90	-	-
Weighted average price per Bbl	$37.30	-	-
Fair value (in millions)	($2.8)	-	-

At March 31, 2006, we had outstanding fixed-price basis differential swaps on 20.0 Bcf of 2006 and 10.0 Bcf of 2007 gas production that did not qualify for hedge accounting treatment. The fair value of these differential swaps was an asset of $12.3 million at March 31, 2006. As of April 27, 2006, we entered into additional hedges on 2.0 Bcf of future gas production subsequent to the end of the quarter.

At December 31, 2005, we had outstanding natural gas price swaps on total notional volumes of 7.9 Bcf at a weighted average price per Mcf of $6.64 in 2006 and 12.0 Bcf at a weighted average price per Mcf of $6.66 in 2007. Outstanding oil price swaps at December 31, 2005 on 120 MBbls are yielding us an average price of $37.30 per barrel during 2006. At December 31, 2005, we also had outstanding natural gas price swaps on total notional gas purchase volumes of 1.8 Bcf in 2006 for which we paid an average fixed price of $12.71 per Mcf.

At December 31, 2005, we had collars in place on 43.0 Bcf in 2006, 28.0 Bcf in 2007 and 2.0 Bcf in 2008 of gas production. The 43.0 Bcf in 2006 has a weighted average floor and ceiling price of $5.47 and $10.13 per Mcf, respectively. The 28.0 Bcf in 2007 has a weighted average floor and ceiling price of $6.64 and $11.91 per Mcf, respectively. The 2.0 Bcf in 2008 has a weighted average floor and ceiling price of $8.00 and $19.40 per Mcf, respectively.

ITEM 4. CONTROLS AND PROCEDURES

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submissions within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of March 31, 2006. There were no changes in our internal control over financial reporting during the three months ended March 31, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

We are subject to litigation and claims that have arisen in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated.

A lawsuit was filed against us in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to our Boure' prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. Our motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, we filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas Supreme Court invited additional briefing by the parties. In March of 2006, the Texas Supreme Court requested that both parties submit full briefs on the merits of the case. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by us and our legal counsel, no accrual for loss is currently recorded.

ITEM 1A. RISK FACTORS.

There were no additions or material changes to the Company's risk factors as disclosed in Item 1A of Part I in the Company's 2005 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(31.1) Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(31.2) Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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

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

Dated: May 2, 2006

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