SOUTHWESTERN ENERGY CO
Form 10-Q
May 01, 2007

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, 2007**

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

(Exact name of the registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 N. Sam Houston Pkwy. E., Suite 125, 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 25, 2007
Common Stock, Par Value $0.01	169,899,428

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

ASSETS

	March 31, 2007	December 31, 2006
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 888	$ 42,927
Accounts receivable	148,201	131,370
Inventories, at average cost	47,861	62,488
Hedging asset - FAS 133	16,574	64,082
Other	23,065	22,969

Total current assets	236,589		323,836
Property, Plant and Equipment, at cost			
Gas and oil properties, using the full cost method, including $178,285,936 in 2007 and $166,826,844 in 2006 excluded from amortization	2,948,230		2,651,427
Gas distribution systems	228,309		226,067
Gathering systems	73,016		51,836
Gas in underground storage	32,254		32,254
Other	82,284		77,702
	3,364,093		3,039,286
Less: Accumulated depreciation, depletion and amortization	1,078,365		1,022,786
	2,285,728		2,016,500
Other Assets	24,481		38,733
Total Assets	$ 2,546,798	$	2,379,069

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

3

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

LIABILITIES AND STOCKHOLDERS' EQUITY

	March 31, 2007	December 31, 2006
	(in thousands)	
Current Liabilities		
Current portion of long-term debt	$ 1,200	$ 1,200
Accounts payable	217,103	266,023
Taxes payable	11,295	16,088
Advances from partners and customer deposits	28,793	31,941
Hedging liability - FAS 133	34,603	23,864
Over-recovered purchased gas costs	13,773	10,580

Current deferred income taxes		-		19,162
Other		14,980		10,002
Total current liabilities		321,747		378,860
Long-Term Debt		327,400		136,600
Other Liabilities				
Deferred income taxes		383,509		370,522
Long-term hedging liability		16,310		4,902
Pension liability		12,844		11,697
Other		29,912		30,811
		442,575		417,932
Commitments and Contingencies				
Minority Interest in Partnership		11,118		11,034
Stockholders' Equity				
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 169,819,348 shares in 2007 and 168,953,893 in 2006		1,698		1,690
Additional paid-in capital		757,093		740,609
Retained earnings		711,845		660,857
Accumulated other comprehensive income (loss)		(26,678)		31,487
		1,443,958		1,434,643
Total Liabilities and Stockholders' Equity	$	2,546,798	$	2,379,069

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

4

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

For the three months ended

	March 31, 2007	March 31, 2006
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 50,988	$ 58,395
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	56,114	28,403
Deferred income taxes	31,251	34,149
Unrealized loss on derivatives	2,474	4,056
Stock-based compensation expense	1,493	1,000
Equity in income of NOARK partnership	-	(925)
Minority interest in partnership	83	291
Change in assets and liabilities:		
Accounts receivable	(16,831)	38,378
Inventories	14,627	15,472
Under/over-recovered purchased gas costs	3,193	1,548
Accounts payable	1,268	(36,224)
Advances from partners and customer deposits	(3,148)	(139)
Other assets and liabilities	(13,101)	(1,035)
Net cash provided by operating activities	128,411	143,369
Cash Flows From Investing Activities		
Capital investments	(372,664)	(156,421)
Proceeds from sale of property, plant and equipment	2,459	65
Other items	(245)	169
Net cash used in investing activities	(370,450)	(156,187)
Cash Flows From Financing Activities		
Payments on revolving long-term debt	(150,800)	-
Borrowings under revolving long-term debt	341,600	-
Debt issuance costs	(1,278)	-
Excess tax benefit for stock-based compensation	11,457	2,562
Change in bank drafts outstanding	(3,901)	(2,235)
Proceeds from exercise of common stock options	2,922	1,149
Net cash provided by financing activities	200,000	1,476
Decrease in cash and cash equivalents	(42,039)	(11,342)
Cash and cash equivalents at beginning of year	42,927	223,705
Cash and cash equivalents at end of period	$ 888	$ 212,363

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

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

	Common Stock		Additional	Retained	Accumulated Other	
	Shares Issued	Amount	Paid-In Capital	Earnings	Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2006	168,954	$ 1,690	$ 740,609	$ 660,857	$ 31,487	$ 1,434,643
Comprehensive income:						
Net Income	-	-	-	50,988	-	50,988
Change in value of derivatives	-	-	-	-	(58,165)	(58,165)
Total comprehensive income (loss)	-	-	-	-	-	(7,177)
Tax benefit for stock-based compensation	-	-	11,457	-	-	11,457
Stock-based compensation - FAS 123(R)	-	-	2,113	-	-	2,113
Exercise of stock options	858	8	2,914	-	-	2,922
Issuance of restricted stock	14	-	-	-	-	-
Cancellation of restricted stock	(7)	-	-	-	-	-
Balance at March 31, 2007	169,819	$ 1,698	$ 757,093	$ 711,845	$ (26,678)	$ 1,443,958

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the three months ended March 31,	
	2007	2006
	(in thousands)	

Balance, beginning of period	$	31,487	$	(104,874)
Current period reclassification to earnings		(12,270)		(1,127)
Current period ineffectiveness		4,923		(1,679)
Current period change in derivative instruments		(50,818)		65,221
Balance, end of period	$	(26,678)	$	(42,459)

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

6

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries

March 31, 2007

(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, which have been reviewed and approved by the audit committee of the Company s Board of Directors, 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, 2006 (the "2006 Annual Report on Form 10-K").

Effective June 30, 2006, Southwestern Energy Company reincorporated from Arkansas to Delaware. As a result of the reincorporation, the Company s common stock now has a par value of $0.01 per share. The reincorporation did not result in any change in the Company s business, management, employees, fiscal year, assets or liabilities.

(2)

GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to the exploration, development, and acquisition of natural 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. 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 natural 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. However, commodity price increases subsequent to the end of a reporting period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At March 31, 2007 and 2006, the Company s unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At March 31, 2007, the ceiling value of the Company s reserves was calculated based upon quoted market prices of $7.34 per Mcf for Henry Hub gas and $62.50 per barrel for West Texas Intermediate oil, adjusted for market differentials, and included approximately $87.5 million related to the positive effects of future cash flow hedges of natural gas production. The Company had approximately 155.0 Bcf of future production hedged at March 31, 2007 (see Item 3 of this Form 10-Q for additional discussion of the Company s hedging activities). A decline in natural gas and oil prices from March 31, 2007 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

7

(3)

EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three months ended March 31, 2007 and 2006, respectively:

	March 31, 2007	March 31, 2006
Net Income (in thousands)	$ 50,988	$ 58,395

Number of Common Shares:				
Weighted average outstanding		168,601,357		166,777,560
Issued upon assumed exercise of outstanding stock options		3,246,205		3,621,362
Effect of issuance of nonvested restricted common shares		184,920		547,579
Weighted average and potential dilutive outstanding (1)		172,032,482		170,946,501
Net Income per Common Share:				
Basic	$	0.30	$	0.35
Diluted	$	0.30	$	0.34

(1)

Options for 436,665 shares for the three months ended March 31, 2007, and for 223,780 shares for the comparable period of 2006, were excluded from the calculations because they would have had an antidilutive effect. Additionally, 9,900 shares of restricted stock for the three months ended March 31, 2007, and 109,414 shares of restricted stock for the comparable period of 2006, were excluded from the calculations because they would have had an antidilutive effect.

(4)

DEBT

Debt balances as of March 31, 2007 and December 31, 2006 consisted of the following:

	March 31, 2007	December 31, 2006
	(in thousands)	
Short-term:		
7.15% Senior Notes due 2018 (current portion)	$ 1,200	$ 1,200
Long-term:		
Variable rate (6.21% at March 31, 2007) unsecured revolving credit arrangements	190,800	-
7.625% Senior Notes due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Senior Notes due 2017	40,000	40,000

7.15% Senior Notes due 2018	36,600	36,600
Total long-term debt	327,400	136,600
Total debt	$ 328,600	$ 137,800

In February 2007, the Company amended its unsecured revolving credit facility increasing the borrowing capacity to $750 million, lowering the borrowing cost and extending the maturity date to 2012. The amount available under the revolving credit facility may be increased to $1 billion at any time upon the Company s agreement with its existing or additional lenders. There was $190.8 million outstanding under the revolving credit facility at March 31, 2007 compared to no amount outstanding at December 31, 2006. The interest rate on the amended credit facility is calculated based upon the Company s debt rating and is currently 87.5 basis points over the current London Interbank Offered Rate (LIBOR). The revolving credit facility is currently guaranteed by the Company s subsidiaries, Southwestern Energy Production Company, SEECO, Inc. and Southwestern Energy Services Company and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The revolving credit facility also 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 stockholders' 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, 2007, the Company s capital structure consisted of 19% debt and 81% equity and it was in compliance with the covenants of its debt agreements.

(5)

DERIVATIVES AND RISK MANAGEMENT

Management enters into various types of derivative instruments for a portion of the Company s projected gas and oil sales to reduce its exposure to market price volatility for natural gas and oil. At March 31, 2007, our gas derivative instruments consisted of price swaps, costless collars and basis swaps. 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, 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 or as a component of other comprehensive income. The Company s hedging practices are summarized in Note 8 of the Notes to Consolidated Financial Statements of the 2006 Annual Report on Form 10-K.

At March 31, 2007, the Company's net liability related to its hedging activities was $28.6 million. Additionally, at March 31, 2007, the Company had recorded a loss to other comprehensive income (loss) of $16.7 million related to its hedging activities. The amount recorded in other comprehensive income (loss) will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Assuming the market prices of gas and oil futures as of March 31, 2007, remain unchanged, the Company would expect to transfer an aggregate after-tax loss of approximately $10.2 million from accumulated other comprehensive income to earnings during the next 12 months. For the three months ended March 31, 2007, the change in accumulated other comprehensive income (loss) related to derivatives was a loss of $93.8 million ($58.2 million after tax) compared to income of $99.1 million ($62.4 million after tax) for the three months ended March 31, 2006. 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's three reportable business segments, Exploration and Production (E&P), Midstream Services and Natural Gas Distribution, have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. 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 properties. Revenues for the Natural Gas Distribution segment arise from the transportation and sale of natural gas at retail.

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 of the Notes to Consolidated Financial Statements included in Item 8 of the 2006 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 (expense) and minority interest in partnership. The "Other" column includes items not related to the Company's reportable segments including real estate, corporate items and the Company s former investment in the Ozark Gas Transmission system.

	Exploration And Production	Midstream Services	Natural Gas Distribution	Other	Total
			(in thousands)		

Three months ended March 31, 2007:					
Revenues from external customers	$ 151,455	$ 56,319	$ 76,878	$ -	$ 284,652
Intersegment revenues	9,806	122,270	116	112	132,304
Operating income	74,310	11	9,381	57	83,759
Interest and other income (loss) (1)	72	-	(51)	-	21
Depreciation, depletion and amortization expense	53,074	1,042	1,634	35	55,785
Interest expense (1)	93	-	1,365	-	1,458
Provision for income taxes (1)	28,197	4	3,027	23	31,251
Assets	2,151,721	148,035	185,956	61,086 (2)	2,546,798 (2)
Capital investments (3)	301,198	21,620	2,604	1,831	327,253
Three months ended March 31, 2006:					
Revenues from external customers	$ 117,437	$ 31,054	$ 78,211	$ -	$ 226,702
Intersegment revenues	11,728	77,620	124	112	89,584
Operating income	80,779	1,070	7,907	48	89,804
Interest and other income (loss) (1)	2,291	1	(49)	933	3,176
Depreciation, depletion and amortization expense	26,247	233	1,597	26	28,103
Interest expense (1)	100	-	45	-	145
Provision for income taxes (1)	30,509	395	2,883	362	34,149
Assets	1,426,708	47,339	189,672	268,165 (2)	1,931,884 (2)
Capital investments (3)	154,907	4,769	3,494	3,375	166,545

(1)

Interest income, interest expense and the provision for income taxes by segment are allocations as they are incurred at the corporate level.

(2)

Other assets include corporate assets not allocated to segments, assets for non-reportable segments and, for the period ended March 31, 2006, the Company s equity investment in NOARK and the Company's investment in cash equivalents.

(3)

Capital investments include a reduction of $46.3 million and an increase of $9.6 million for the three-month periods ended March 31, 2007 and 2006, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $107.0 million and $63.5 million for the first quarters of 2007 and 2006, respectively, for marketing of the Company's E&P sales. Intersegment sales by the E&P segment and Midstream Services segment to the Natural Gas Distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures and prepaid debt 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,	
	2007	2006
	(in thousands)	
Interest payments	$ 1,181	$ 632
Income tax payments	$ -	$ -

(8)

CONTINGENCIES AND COMMITMENTS

Operating Commitments

The Company has various operating commitments in the normal course of its operations. Other than the agreement mentioned below, there have been no material changes to the Company s operating commitments as disclosed in the 2006 Annual Report on Form 10-K.

During the first quarter of 2007, one of the Company's E&P subsidiaries renegotiated a previous agreement with a rig operating company, resulting in the net reduction of future commitments for rig operating fees by approximately

$20.6 million over the next three years.

Environmental

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 adverse effect on the financial position or results of operations of the Company.

Litigation

The Company is subject to litigation and claims that arise 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 litigation and claims currently pending will not have a material adverse effect on the financial position or results of operations 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 Company settled this lawsuit in the first quarter of 2007. The settlement amount was accrued for in the fourth quarter of 2006.

(9)

STOCK-BASED COMPENSATION

The Company has incentive plans that provide for the issuance of equity awards, including stock options and restricted stock. These plans are discussed more fully in Note 9 of the Notes to Consolidated Financial Statements included in Item 8 of the 2006 Annual Report on Form 10-K. The Company has issued options and restricted stock under these plans. 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 stock options were granted in the first quarter of 2007. 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 and have met the minimum service requirements in order to become fully vested prior to the requisite service period.

For the three months ended March 31, 2007, the Company recognized compensation costs of $929,000 related to stock options. Of this amount, $174,000 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. As a result, the Company recorded a deferred tax benefit of $261,000. A total of $5,507,000 of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods.

For the three month period ended March 31, 2007, restricted stock expense recorded in general and administrative expenses was $738,000 and an additional $445,000 was capitalized into the full cost pool. As of March 31, 2007, there was $11,622,000 of total unrecognized compensation cost related to nonvested shares of restricted stock.

12

The following tables summarize stock option activity for the first three months of 2007 and provides information for options outstanding at March 31, 2007:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2006	5,792,240	$ 6.19
Granted	-	-
Exercised	858,578	3.40
Forfeited or expired	-	-
Outstanding at March 31, 2007	4,933,662	$ 6.68
Exercisable at March 31, 2007	4,373,358	$ 3.81

There were no options granted during the first three months of 2007 and 2006. The total intrinsic value of options exercised during the first three months of 2007 and 2006 was $31.2 million and $10.9 million, respectively. Associated with the exercise of stock options, the Company received a tax benefit of $11.5 million and $2.6 million in the first three months of 2007 and 2006, respectively. The tax benefit is recorded as an increase in additional paid-in capital.

	Options Outstanding				Options Exercisable		
Range of Exercise Prices	Options Outstanding at March 31, 2007	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at March 31, 2007	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$1.50 - $1.86	1,959,377	$ 1.74	3.3		1,959,377	$ 1.74	
$1.87 - $2.85	570,708	2.53	3.8		570,708	2.53	
$2.86 - $5.00	799,306	2.90	5.4		799,306	2.90	
$5.01 - $12.00	775,128	5.51	6.7		729,794	5.45	
$12.01 - $41.00	829,143	25.95	5.5		314,173	17.57	
	4,933,662	$ 6.68	4.6	$ 169,225	4,373,358	$ 3.81	$ 162,562

The following table summarizes restricted stock activity for the first quarter of 2007:

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2006	478,732	$ 25.30
Granted	14,300	39.58
Vested	(7,067)	7.35
Forfeited	(7,423)	32.73
Unvested shares at March 31, 2007	478,542	$ 25.87

(10)

PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." 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, 2007 and 2006:

	Pension Benefits For the three months ended March 31,	
	2007	2006
	(in thousands)	
Service cost	$ 996	$ 752
Interest cost	1,060	970
Expected return on plan assets	(1,140)	(1,144)
Amortization of prior service cost	119	109
Amortization of net loss	115	190
Net periodic benefit cost	$ 1,150	$ 877

	Postretirement Benefits For the three months ended March 31,	
	2007	2006
	(in thousands)	
Service cost	$ 104	$ 68
Interest cost	54	47
Expected return on plan assets	(20)	(17)
Amortization of net loss	5	8
Amortization of transition obligation	22	22
Net periodic benefit cost	$ 165	$ 128

The Company currently expects to contribute $6.6 million to the pension plans and $0.4 million to the postretirement benefit plans in 2007. As of March 31, 2007, there have been no contributions to the pension plans, and $0.1 million has been contributed to the postretirement benefit plans.

(11)

ASSET RETIREMENT OBLIGATIONS

Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," (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, 2007 and for the year ended December 31, 2006:

	March 31, 2007	December 31, 2006
	(in thousands)	
Asset retirement obligation at January 1	$ 10,545	$ 9,229
Accretion of discount	109	401
Obligations incurred	437	1,152
Obligations settled/removed	(182)	(645)
Revisions of estimates	-	408
Asset retirement obligation at March 31, 2007 and December 31, 2006	$ 10,909	$ 10,545
Current liability	643	593
Long-term liability	10,266	9,952
Asset retirement obligation at March 31, 2007 and December 31, 2006	$ 10,909	$ 10,545

(12)

NEW ACCOUNTING PRONOUNCEMENTS

During the first quarter of fiscal 2007, the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a threshold condition that a tax position must meet to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 was effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 had no material impact on the Company s results of operations and financial condition. The income tax years 2003-2006 remain open to examination by the major taxing jurisdictions to which the Company is subject.

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 2006 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three-month periods ended March 31, 2007 and 2006. 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 2006 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" in Part I and elsewhere in our 2006 Annual Report on Form 10-K and Item 1A, Risk Factors in Part II in this Form 10-Q. You should read the following discussion with our financial statements and related notes included in this Form 10-Q.

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, and New Mexico. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas distribution and marketing 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 (E&P), Midstream Services and Natural Gas Distribution.

Our business strategy is focused on providing long-term growth in the net asset value of our business, which we achieve in our E&P business through the drillbit. In our E&P business, we prepare economic analyses for each of our drilling and acquisition opportunities and rank them based upon the expected present value added for each dollar invested, which we refer to as PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. We target creating at least $1.30 of discounted pre-tax PVI for each dollar we invest in our E&P projects. Our actual PVI results are utilized to help determine the allocation of our future capital investments.

We 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. In recent years, there has been significant price volatility in natural gas and crude oil prices 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, which determines the pricing. 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.

In the first quarter of 2007, our gas and oil production increased to 22.9 Bcfe, up 44% from the first quarter of 2006. The increase in 2007 production primarily resulted from an increase in production from our Fayetteville Shale play.

We reported net income of $51.0 million in the first quarter of 2007, or $0.30 per share on a fully diluted basis, down 13% from the prior year, as increased production volumes in our E&P segment were more than offset by lower realized average natural gas prices, which were down 15% from the first quarter of 2006, and increased operating costs and expenses. Our cash flow from operating activities was $128.4 million in the first quarter of 2007, down from $143.4 million due primarily to changes in operating assets and liabilities. Operating income for our E&P segment was $74.3 million for the first quarter of 2007, down from $80.8 million in the comparable period of 2006 as lower realized prices for our gas production and increased operating costs and expenses more than offset our increased production volumes. Operating income for our Midstream Services segment was approximately breakeven in first quarter of 2007, compared to $1.1 million in the first quarter of 2006, due to increased operating costs and expenses for our gas gathering activities due in part to timing differences, and a decrease in the margin generated by our gas marketing activities. Operating income for our Natural Gas Distribution segment increased to $9.4 million in the first quarter of 2007, up from $7.9 million in the comparable period of 2006, primarily due to comparatively colder weather.

Our capital investments during the first quarter of 2007 almost doubled from the prior year to $327.3 million, of which $301.2 million was invested in our E&P segment. The prior year s first quarter capital investments of $166.5 million included $154.9 million invested in our E&P segment, of which $23.1 million was invested in drilling rigs that were ultimately sold and leased back in December 2006.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended March 31, 2007	2006
Revenues (in thousands)	$161,261	$129,165
Operating income (in thousands)	$74,310	$80,779
Gas production (MMcf)	21,886	14,836
Oil production (MBbls)	167	177
Total production (MMcfe)	22,891	15,896
Average gas price per Mcf, including hedges	$6.71	$7.86
Average gas price per Mcf, excluding hedges	$6.19	$7.60
Average oil price per Bbl, including hedges	$55.17	$56.80
Average oil price per Bbl, excluding hedges	$55.17	$60.63
Average unit costs per Mcfe		
Lease operating expenses	$0.74	$0.53
General & administrative expenses	$0.47	$0.53
Taxes, other than income taxes	$0.27	$0.33
Full cost pool amortization	$2.24	$1.59

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up 25% for the three months ended March 31, 2007 as our increased production volumes were partially offset by lower average realized natural gas and oil prices. Revenues for the first three months of 2007 and 2006 also include pre-tax gains of $5.1 million and $1.9 million, respectively, related to the sale of gas in storage inventory. We expect our production volumes to continue to increase primarily due to the development of our Fayetteville Shale play in Arkansas. Gas and oil prices are difficult to predict and subject to wide price fluctuations. As of April 30, 2007, we have hedged 64.0 Bcf of our remaining 2007 gas production, 75.0 Bcf of 2008 gas production and 28.0 Bcf of 2009 gas production to limit our exposure to price fluctuations.

Operating Income. Operating income for the E&P segment was down 8% for the first quarter of 2007 primarily due to a 15% decline in realized natural gas prices and increased operating costs and expenses, which more than offset the effects of an increase in production.

Production. Gas and oil production during the first quarter of 2007 was up approximately 44% to 22.9 Bcfe as compared to the prior period. Our total gas production was up approximately 48% to 21.9 Bcf for the first quarter of 2007 and represented approximately 96% of our total equivalent production. The increases were primarily the result of increased production from our Fayetteville Shale play. Net production from the Fayetteville Shale was 8.2 Bcf in the first quarter of 2007, compared to 0.7 Bcf in the first quarter of 2006. As of April 30, 2007, our gross production rate from our Fayetteville Shale properties approximated 155.0 MMcf per day.

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 and Note 5 of the Notes to Consolidating Financial Statements in this Form 10-Q for additional discussion). The average price realized for our gas production, including the effect of hedges, decreased approximately 15% to $6.71 per thousand cubic feet (Mcf) for the three months ended March 31, 2007, as compared to the same period last year. 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 $0.52 per Mcf during the first quarter of 2007, compared to $0.26 per Mcf during the same period of 2006. Locational differences in market prices for natural gas have continued to be wider than historically experienced. We had financially protected approximately 86% of our production in the first quarter of 2007 from the impact of widening basis differentials. For the remainder of 2007, we have protected approximately 75% of our anticipated gas production from the impact of widening basis differentials through our hedging activities and sales arrangements. Disregarding the impact of hedges, the average price received for our gas production during the first three months of 2007 was approximately $0.58 lower than average NYMEX spot prices.

For the remainder of 2007, we have NYMEX commodity price hedges in place for 64.0 Bcf of our gas production and for 2008 and 2009 we have 75.0 Bcf and 28.0 Bcf, respectively, of our future gas production hedged. Additionally, we have basis swaps on 49.3 Bcf for the remainder of 2007, and for

2008 we have basis swaps on 42.3 Bcf in order to reduce the effects of changes in market differentials on prices we receive.

We realized an average price of $55.17 per barrel for our oil production during the three months ended March 31, 2007, down approximately 3% from the same period of 2006. In the first quarter of 2006, the average price we received for our oil production was reduced by $3.83 per barrel due to the effects of our hedging activities. Currently, we do not have any open hedges on future oil production.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment increased 40% to $0.74 for the first quarter of 2007, compared to the first quarter of 2006, primarily as a result of increases in our gathering and compression costs related to our operations in the Fayetteville Shale play. Based on our projected production, we expect our per unit operating costs for 2007 to range between $0.82 and $0.87 per Mcfe.

General and administrative expenses per Mcfe decreased 11% to $0.47 for the first quarter of 2007, compared to the first quarter of 2006, due primarily to the effects of our increased production volumes. Total general and administrative expenses for our E&P segment were $10.8 million in the first quarter of 2007, compared to $8.5 million in the first quarter of 2006. We expect our per unit G&A expense to continue to decline for the remainder of 2007 and to range between $0.41 and $0.46 per Mcfe for the year due to increased production volumes from our Fayetteville Shale play.

Our full cost pool amortization rate averaged $2.24 per Mcfe for the first quarter of 2007, up 41% compared to the same period in 2006, and is expected to range between $2.20 and $2.40 per Mcfe for the year. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, and the level of unevaluated costs excluded from amortization. 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 amount of future reserves attributed to our Fayetteville Shale play. Unevaluated costs excluded from amortization were $178.3 million at March 31, 2007, compared to $131.1 million at March 31, 2006. The increase in unevaluated costs since March 31, 2006 resulted primarily from an increase in our undeveloped leasehold acreage related to our Fayetteville Shale play and our increased drilling activity.

We utilize the full cost method of accounting for costs related to the exploration, development, and acquisition of natural 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. 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 natural 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. However, commodity price increases subsequent to the end of a reporting period but prior to the release of periodic reports may be utilized to calculate the ceiling value

of reserves. At March 31, 2007 and 2006, the Company s unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At March 31, 2007, the ceiling value of our reserves was calculated based upon quoted market prices of $7.34 per Mcf for Henry Hub gas and $62.50 per barrel for West Texas Intermediate oil, adjusted for market differentials, and included approximately $87.5 million related to the positive effects of future cash flow hedges of natural gas production. We had approximately 155.0 Bcf of future production hedged at March 31, 2007 (see Item 3 of this Form 10-Q for additional discussion of our hedging activities). A decline in natural gas and oil prices from March 31, 2007 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

Taxes other than income taxes per Mcfe decreased 18% to $0.27 for the first quarter of 2007 due primarily to the effects of lower gas and oil prices and the changing mix of production.

The timing and amount of production and reserve additions attributed to our Fayetteville Shale play could have a material impact on per unit costs; if production or reserves additions are lower than projected, our per unit costs would increase.

Midstream Services

	For the three months ended March 31,	
	2007	2006
	($ in thousands)	
Revenues	$178,589	$108,674
Gas purchases	$171,679	$105,533
Operating costs and expenses	$6,899	$2,071
Operating income	$11	$1,070
Gas volumes marketed (Bcf)	27.1	13.8

Revenues from our Midstream Services segment were up 64% in the first quarter of 2007, as compared to the prior year period. The increase in first quarter revenues primarily resulted from an increase in volumes marketed and increased gathering revenues. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expense. Midstream Services had gathering revenues of $4.9 million in the first quarter of 2007, compared to $0.6 million for the comparable period of 2006. Gathering revenues and expenses for this segment are expected to continue to grow in the future as reserves related to our Fayetteville Shale play are developed and production increases. Operating income from our Midstream Services segment decreased in the first quarter of 2007, compared to the first quarter of 2006, primarily due to increased operating costs and expenses for our gas gathering activities due in part to timing differences, and a decrease in the margin generated by our gas marketing activities. 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. The increase in volumes marketed in the first quarter of 2007, as compared to the same period in 2006, resulted from increased production volumes in the Fayetteville Shale play. We marketed 19.5 Bcf of affiliated gas in the first quarter of 2007, representing 72% of total volumes marketed, compared to 9.7 Bcf, or 70% of total volumes marketed, for the same period in 2006. 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.

Natural Gas Distribution

	For the three months ended March 31, 2007	2006
Revenues (in thousands)	$76,994	$78,335
Gas purchases (in thousands)	$54,217	$56,505
Operating costs and expenses (in thousands)	$13,396	$13,923
Operating income (in thousands)	$9,381	$7,907
Deliveries (Bcf)		
Sales and end-use and off-system transportation	9.5	8.4
Sales customers at period-end	152,864	149,486
Average sales rate per Mcf	$10.68	$13.11
Heating weather - degree days	1,941	1,787
Percent of normal	89%	82%

Revenues and Operating Income

Revenues for the first quarter of 2007 decreased slightly from the comparable period of 2006 due primarily to lower average sales rates caused by lower prices paid for natural gas supplied to customers.

Operating income for our Natural Gas Distribution segment increased 19% in the first quarter of 2007, as compared to the same period of 2006, due primarily to the increase in volumes delivered as weather during the first three months of 2007 was 7% colder than the same period in 2006, although it was still 11% warmer than normal.

Deliveries and Rates

For the three-month period ended March 31, 2007, deliveries increased 13% to 9.5 Bcf, compared to the same period of 2006, due to the comparatively colder weather. The average sales rate per Mcf decreased in the first quarter of 2007 due to changes in natural gas prices.

Our utility segment hedged 3.1 Bcf of derivative gas purchases in the first three months of 2007 which had the effect of increasing its total gas supply cost by $6.6 million. In the first three months of 2006, our utility hedged 1.8 Bcf of its gas supply which increased its total gas supply cost by $6.8 million. See Note 5 of the Notes to Consolidating Financial Statements and Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

Operating Costs and Expenses

For the first quarter of 2007, operating costs and expenses (exclusive of purchased gas costs) for this segment were lower than the comparable period of the prior year due primarily to lower general and administrative expenses. The decrease in general and administrative expenses primarily resulted from a decrease in corporate expenses allocated to the natural gas distribution segment.

Transportation

In the second quarter of 2006, we sold our 25% partnership interest in NOARK Pipeline System Limited Partnership (NOARK). We recorded pre-tax income of $0.9 million from operations related to our investment in NOARK for the first quarter of 2006. This amount was recorded in other income in our statements of operations.

Other Revenues

Other revenues for the first three months of 2007 and 2006 included pre-tax gains of $5.1 million and $1.9 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, increased to $1.5 million for the first quarter of 2007, compared to $0.1 million for the first quarter of 2006, due to increased debt levels resulting from our increased level of capital investments, partially offset by an increase in the level of capitalized interest. Interest capitalized increased to $3.0 million in the first three months of 2007, as compared to $2.4 million for the same period in 2006. The increase in capitalized interest is primarily due to our increased level of investment in unevaluated properties. Costs excluded from amortization in the E&P segment increased to $178.3 million at March 31, 2007, compared to $131.1 million at March 31, 2006.

During the first quarter of 2007 we earned interest income of $0.1 million related to cash equivalents, compared to $2.3 million in the first quarter of 2006. These amounts are recorded in other income. We had no cash investments at March 31, 2007.

Income Taxes

In 2006, the state of Texas enacted legislation to replace its method of taxing businesses from a capital based tax to a tax on modified gross revenue which resulted in our recording of additional income taxes in the second quarter of 2006 and in subsequent periods. Our provision for deferred income taxes was an effective rate of 38.0% for the first three months ended March 31, 2007 as a result of this legislation, compared to 36.9% for the three months ended March 31, 2006. Other than the change resulting from Texas taxes discussed above, 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 $1.3 million in the first quarter of 2007 for our pension and other postretirement benefit plans, compared to $1.0 million for the same period of 2006. 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 $7.0 million to our pension and other postretirement plans in 2007. As of March 31, 2007, there has been no contribution 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 Notes to Consolidating Financial Statements in this Form 10-Q.

Stock-Based Compensation

We recognized expense of $1.5 million and capitalized $0.6 million to the full cost pool for stock-based compensation in the first three months of 2007, compared to $1.0 million expensed and $0.4 million capitalized to the full cost pool in the first quarter of 2006. We refer you to Note 9 of the Notes to Consolidating Financial Statements in this Form 10-Q for additional discussion of our equity based compensation plans.

Adoption of Accounting Principles

During the first quarter of fiscal 2007, we adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in FAS 109. FIN 48 prescribes a threshold condition that a tax position must meet to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 was effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 had no material impact on our results of operations and financial condition.

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 $750 million under our revolving credit facility from time to time. The amount available under our revolving credit facility may be increased up to $1 billion at any time upon our agreement with our existing or additional lenders. As of March 31, 2007, we had $190.8 million outstanding under our revolving credit facility. At December 31, 2006, we had no indebtedness outstanding under our revolving credit facility.

Net cash provided by operating activities decreased 10% to $128.4 million in the first three months of 2007, compared to the first quarter in 2006, due primarily to changes in operating assets and liabilities. For the first three months of 2007, requirements for capital expenditures were met primarily by our revolving credit facility, cash provided by operating activities, and cash equivalents from the sale and operating leaseback of our drilling rigs on December 29, 2006.

At March 31, 2007, our capital structure consisted of 19% debt and 81% equity. We believe that our operating cash flow and borrowings under our credit facility will be adequate to meet our capital

and operating requirements for the remainder of 2007, however, we may also raise funds in the public debt and equity markets to meet a portion of our cash requirements.

Our cash flow from operating activities is highly dependent upon market prices that we receive for our gas and oil production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Item 3, "Quantitative and Qualitative Disclosures about Market Risks" and Note 5 to the Notes to Consolidating Financial Statements in this Form 10-Q. 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 Investments

Our capital investments almost doubled to $327.3 million (including a reduction of $46.3 million in accrued expenditures from December 31, 2006 to March 31, 2007) for the first three months of 2007 as compared to the same period last year, of which $301.2 million was invested in our E&P segment. E&P segment investments in the first quarter of 2006 were $154.9 million, including $23.1 million for drilling rigs that were subsequently sold and leased back in December 2006. Our projected capital investments for 2007 of $1,341 million include approximately $1,237 million related to our E&P segment, of which we expect to allocate approximately $875 million to our Fayetteville Shale play. Our capital investment program for the remainder of 2007 is expected to be funded through cash flow from operations and borrowings under our revolving credit facility. We may also raise funds in the public debt and equity markets to fund a portion of our capital investment program. We may also adjust our level of 2007 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 $328.6 million at March 31, 2007, compared to $137.8 million at December 31, 2006. Our revolving credit facility was amended in February 2007, increasing our borrowing capacity to $750 million with an accordion feature for an additional $250 million, lowering our borrowing cost and extending the maturity date to February 2012. At March 31, 2007, we had $190.8 million debt under our revolving credit facility. The interest rate on the facility is calculated based upon our public debt rating and is currently 87.5 basis points over LIBOR. The revolving credit facility is currently guaranteed by our subsidiaries, Southwestern Energy Production Company, SEECO, Inc. and Southwestern Energy Services Company and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. Our publicly traded notes were downgraded on August 1, 2006 by Standard and Poor s to BB+ with a stable outlook from BBB- with a negative outlook. We have a Corporate Family Rating of Ba2 by Moody s, and our publicly traded notes were rated Ba3 by Moody s under Moody s Loss Given Default Assessment on September 19, 2006. Any future downgrades in our public debt ratings could increase our cost of funds under the credit facility. We do not expect our current ratings to impact our ability to obtain acceptable financing terms if we elect to access the public debt market in the future.

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 stockholders 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, 2007. 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 investment plans.

At March 31, 2007, our capital structure consisted of 19% debt and 81% equity. Stockholders equity in the March 31, 2007 balance sheet includes an accumulated other comprehensive loss of $16.7 million related to our hedging activities that is required to be recorded under the provisions of Statement on Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133), and a loss of $9.9 million related to changes in our pension liability and the adoption FAS 158. The amount recorded for FAS 133 is based on current market values of our hedges at March 31, 2007, 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 and FAS 158 and the non-cash impact of any full cost ceiling write-downs. Our capital structure at March 31, 2007 would be 18% debt and 82% equity without consideration of the accumulated other comprehensive losses related to FAS 133 and FAS 158.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 75% of our expected 2007 gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans. If commodity prices remain at or near their current levels throughout the remainder of 2007, our capital investment plans do not change and we do not issue equity, we will increase our long-term debt in 2007 by approximately $700 to $750 million. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital investments.

Off-Balance Sheet Arrangements

On May 2, 2006, we sold our 25% partnership interest in NOARK to Atlas Pipeline Partners, L.P., for $69.0 million. As part of the transaction, we assumed and recorded $39.0 million of debt obligations of NOARK Pipeline Finance, L.L.C., which we had previously guaranteed as part of the financing of NOARK.

On December 29, 2006, we entered into a sale/leaseback transaction pursuant to which we sold 13 operating drilling rigs, two rigs yet to be delivered and related equipment and then leased such drilling rigs and equipment from the buyer for an initial term of eight years from January 1, 2007 for rental payments of approximately $19.6 million annually. Subject to certain conditions, we have options to purchase the rigs and related equipment from the lessors at the end of the 84th month of the lease term at an agreed upon price or at the end of the lease term for its then fair market value. Additionally, we have the option to renew each lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Other than the agreement mentioned below, there have been no material changes to our contractual obligations as disclosed in our 2006 Annual Report on Form 10-K.

During the first quarter of 2007, one of our E&P subsidiaries renegotiated a previous agreement with a rig operating company, resulting in the net reduction of our future commitments for rig operating fees by approximately $20.6 million over the next three years.

Contingent Liabilities and Commitments

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 $5.3 million in 2007 for these plans, of which $1.3 million has been recorded in the first three months of 2007. At March 31, 2007, we had an accrued pension benefit liability recorded of $12.8 million. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 10 of the Notes to Consolidating Financial Statements in this Form 10-Q.

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 our Boure' prospect in Louisiana. We settled this lawsuit in the first quarter of 2007. The settlement amount was accrued for in the fourth quarter of 2006.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our credit facility described above. We had negative working capital of $85.2 million at March 31, 2007, and negative working capital of $55.0 million at December 31, 2006. Current assets decreased at March 31, 2007 primarily due to a decrease of $42.0 million in cash equivalents and a $47.5 million decrease in our hedging asset. Current liabilities decreased $57.1 million primarily due to a decrease in our accounts payable at March 31, 2007.

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 8.1 Bcf at $3.52 per Mcf at March 31, 2007, and 9.6 Bcf at $3.89 per Mcf at December 31, 2006.

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 natural gas distribution business, especially during periods of colder weather. As a result, demand fees paid by the Natural 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.

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, 2007. In addition, please see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At March 31, 2007, we had $328.6 million of total debt with an average interest rate of 6.70%. Our $750 million revolving credit facility has a floating interest rate (6.21% at March 31, 2007). At March 31, 2007, we had $190.8 million of 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 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 limit our 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, 2007, the fair value of these financial instruments was a $28.6 million liability.

	Volume	Weighted Average Price to be Swapped ($)	Weighted Average Floor Price ($)	Weighted Average Ceiling Price ($)	Weighted Average Basis Differential ($)	Fair Value at Mar 31, 2007 ($ in millions)
Natural Gas (Bcf):						

Fixed Price Swaps:						
2007 (1)	41.8	7.79	-	-	-	(15.1)
2008	27.0	8.28	-	-	-	(5.1)
2009	8.0	7.46	-	-	-	(2.1)
Costless Collars:						
2007	23.5	-	6.75	10.38	-	(4.3)
2008	44.0	-	7.86	11.65	-	(0.3)
2009	12.0	-	7.83	10.51	-	(3.2)
Basis Swaps:						
2007	27.7	-	-	-	(0.52)	(0.2)
2008	34.3	-	-	-	(0.47)	(1.1)
Matched-Basis Swaps:						
2007	21.6	-	-	-	(0.40)	3.5
2008	8.0	-	-	-	(0.73)	(0.7)

(1)

Includes fixed price swaps for 1.3 Bcf relating to gas marketing activities for which a fair value hedge liability of $0.1 million was recognized at March 31, 2007.

At March 31, 2007, we had outstanding fixed-price basis differential swaps on 27.7 Bcf of 2007 and 34.3 Bcf of 2008 gas production that did not qualify for hedge accounting treatment. The fair value of these differential swaps was a liability of $1.3 million at March 31, 2007. As of April 30, 2007, we entered into additional hedges on 12.0 Bcf of future gas production subsequent to the end of the quarter.

At December 31, 2006, the Company had outstanding natural gas price swaps on total notional volumes of 32.5 Bcf in 2007 and 13.0 Bcf in 2008 for which the Company will receive fixed prices ranging from $6.20 to $12.06 per MMBtu. At December 31, 2006, the Company had outstanding fixed price basis differential swaps on 62.0 Bcf of 2007 and 2008 gas production that did not qualify for hedge treatment.

At December 31, 2006, the Company had collars in place on notional volumes of 34.0 Bcf in 2007 and 22.0 Bcf in 2008. The 34.0 Bcf in 2007 had an average floor and ceiling price of $6.93 and $12.34 per MMBtu, respectively. The 22.0 Bcf in 2008 had an average floor and ceiling price of $7.92 and $13.15 per MMBtu, 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, as amended (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, 2007. There were no changes in our internal control over financial reporting during the three months ended March 31, 2007, 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.

The Company is subject to litigation and claims that arise 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 Company settled this lawsuit in the first quarter of 2007. The settlement amount was accrued for in the fourth quarter of 2006.

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 2006 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: April 30, 2007

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