SOUTHWESTERN ENERGY CO
Form 10-Q
April 28, 2008

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, 2008**

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 12 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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer X Accelerated filer ___ Non-accelerated filer ___ Smaller reporting company ___

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 22, 2008
Common Stock, Par Value $0.01	341,963,375

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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, except as may be required by law.

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, targ

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:

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the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);

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the timing and extent of our success in discovering, developing, producing and estimating reserves;

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the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play overall as well as relative to other productive shale gas plays;

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our ability to fund our planned capital investments;

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our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;

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the impact of federal, state and local government regulation, including any increase in severance taxes;

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the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services, including pressure pumping equipment and crews in the Arkoma basin;

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our future property acquisition or divestiture activities;

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the effects of weather;

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increased competition;

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the financial impact of accounting regulations and critical accounting policies;

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the comparative cost of alternative fuels;

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conditions in capital markets and changes in interest rates, and;

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any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission (SEC).

We caution you that these forward-looking statements contained in this Form 10-Q 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 Annual Report on Form 10-K for the year ended December 31, 2007 (the 2007 Annual Report on Form 10-K), and all quarterly reports on Form 10-Q filed subsequently thereto, including this Form 10-Q (Form 10-Qs).

Should one or more of the risks or uncertainties described above or elsewhere in 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.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

ASSETS

	March 31, 2008	December 31, 2007
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 471	$ 727
Accounts receivable	216,903	177,680
Inventories, at average cost	22,139	33,034
Hedging asset - FAS 133	13,084	64,472
Deferred income tax benefit	69,345	-
Current assets held for sale (see Note 4)	51,973	58,877
Other	23,468	28,551
Total current assets	397,383	363,341
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $455.7 million in 2008 and $372.4 million in 2007 excluded from amortization	4,393,487	4,020,448
Gathering systems	190,113	158,604
Gas in underground storage	13,349	13,349
Other	90,044	85,983
	4,686,993	4,278,384

Less: Accumulated depreciation, depletion and amortization		1,296,250		1,200,754
		3,390,743		3,077,630
Assets Held for Sale (see Note 4)		142,310		143,234
Other Assets		44,326		38,511
Total Assets	$	3,974,762	$	3,622,716

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

LIABILITIES AND STOCKHOLDERS' EQUITY

		March 31, 2008		December 31, 2007
		(in thousands)		
Current Liabilities				
Current portion of long-term debt	$	1,200	$	1,200
Accounts payable		346,857		313,070
Taxes payable		6,542		5,087
Advances from partners		33,203		32,005
Hedging liability - FAS 133		209,245		8,598
Current deferred income taxes		-		20,909
Current liabilities associated with assets held for sale (see Note 4)		33,759		39,118
Other		21,427		10,908
Total current liabilities		652,233		430,895
Long-Term Debt		1,076,600		977,600
Other Liabilities				
Deferred income taxes		519,780		479,196

Long-term hedging liability	78,793	15,186
Pension liability	13,628	12,268
Liabilities associated with assets held for sale (see Note 4)	18,639	15,417
Other	37,398	35,084
	668,238	557,151
Commitments and Contingencies		
Minority Interest in Partnership	10,705	10,570
Stockholders' Equity		
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 341,952,429 shares in 2008 and 341,581,672 in 2007 (1)	3,420	3,416
Additional paid-in capital (1)	755,800	752,369
Retained earnings	991,060	882,031
Accumulated other comprehensive income (loss)	(178,578)	13,348
Common stock in treasury, 224,393 shares in 2008 and 222,774 in 2007 (1)	(4,716)	(4,664)
	1,566,986	1,646,500
Total Liabilities and Stockholders' Equity	$ 3,974,762	$ 3,622,716

(1) 2007 restated to reflect the two-for-one stock split effected on March 25, 2008.

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,

	2008	2007
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 109,029	$ 50,988
Adjustments to reconcile net income to		
net cash provided by operating activities:		
Depreciation, depletion and amortization	97,635	56,114
Deferred income taxes	66,824	31,251
Unrealized loss on derivatives	7,636	2,474
Stock-based compensation expense	2,458	1,493
Minority interest in partnership	135	83
Change in assets and liabilities:		
Accounts receivable	(39,007)	(16,831)
Inventories	21,218	14,627
Under/over-recovered purchased gas costs	(3,792)	3,193
Accounts payable	13,156	1,268
Advances from partners and customer deposits	1,193	(3,148)
Other assets and liabilities	20,602	(13,101)
Net cash provided by operating activities	297,087	128,411
Cash Flows From Investing Activities		
Capital investments	(391,029)	(372,664)
Proceeds from sale of property, plant and equipment	895	2,459
Other items	(433)	(245)
Net cash used in investing activities	(390,567)	(370,450)
Cash Flows From Financing Activities		
Payments on revolving long-term debt	(927,400)	(150,800)
Borrowings under revolving long-term debt	426,400	341,600
Proceeds from issuance of long-term debt	600,000	-
Debt issuance costs	(8,883)	(1,278)
Excess tax benefit for stock-based compensation	-	11,457
Change in bank drafts outstanding	2,919	(3,901)
Proceeds from exercise of common stock options	818	2,922
Net cash provided by financing activities	93,854	200,000
Increase (decrease) in cash and cash equivalents	374	(42,039)
Cash and cash equivalents at beginning of year	1,832	42,927
Cash and cash equivalents at end of period	$ 2,206	$ 888

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 [1] Shares Issued	Common Stock Amount	Additional Paid-In Capital [1]	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
(in thousands)							
Balance at December 31, 2007	341,578	$ 3,416	$ 752,369	$ 882,031	$ 13,348	$ (4,664)	$ 1,646,500
Comprehensive income:							
Net income	-	-	-	109,029	-	-	109,029
Change in value of derivatives	-	-	-	-	(192,135)	-	(192,135)
Change in value of pension liability							

- - - - 209 - 209

Total comprehensive income (loss)

(82,897)

Stock-based compensation - FAS 123(R)

- - 2,550 - - - 2,550

Exercise of stock options

365 4 814 - - - 818

Issuance of restricted stock

13 - - - - - -

Cancellation of restricted stock

(7)- - - - - -

Issuance of stock awards

3 - 67 - - - 67

Treasury stock - non-qualified plan

-

- - - - (52) (52)

Balance at March 31, 2008

341,952

$

3,420

$

755,800

$

991,060

$

(178,578)

$

(4,716)

$

1,566,986

(1) 2007 restated to reflect the two-for-one stock split effected on March 25, 2008.

STATEMENT OF COMPREHENSIVE INCOME (LOSS)

	For the three months ended March 31,			
	2008		2007	
	(in thousands)			
Net income	$	109,029	$	50,988
Change in value of derivatives				
Current period reclassification to earnings		(11,712)		(12,270)
Current period ineffectiveness		8,459		4,923
Current period change in derivative instruments		(188,882)		(50,818)
Total change in value of derivatives		(192,135)		(58,165)
Current period change in pension and other postretirement liability		209		-
Comprehensive income (loss), end of period	$	(82,897)	$	(7,177)

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries

March 31, 2008

(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, 2007 (the "2007 Annual Report on Form 10-K").

In February 2008, the Board of Directors declared a two-for-one stock split with respect to the Company s common stock, which was effected in March 2008. All historical per share information in the financial statements and footnotes has been adjusted to reflect the two-for-one stock split.

Certain reclassifications have been made to the prior years financial statements to conform to the 2008 presentation. The effects of the reclassifications were not material to the Company s consolidated financial statements.

(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, 2008 and 2007, the Company s unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At March 31, 2008, the ceiling value of the Company s reserves was calculated based upon quoted market prices of $9.37 per Mcf for Henry Hub gas and $98.00 per barrel for West Texas Intermediate oil, adjusted for market differentials. Cash flow hedges of gas production in place at March 31, 2008, decreased the calculated ceiling value by approximately $99.7 million (net of tax). The Company had approximately 259.5 Bcf of future gas production hedged at March 31, 2008. Decreases in market prices from March 31, 2008 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs could result in future ceiling test impairments.

(3)

EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three months ended March 31, 2008 and 2007, respectively. For the period ended March 31, 2007, all shares and per share amounts (including exercise prices for assumed exercises of stock options) have been restated to reflect the two-for-one stock split effected on March 25, 2008:

	For the three months ended March 31,	
	2008	2007
Net Income (in thousands)	$ 109,029	$ 50,988

Number of Common Shares:		
Weighted average outstanding	341,064,247	337,202,714
Issued upon assumed exercise of outstanding stock options	6,797,795	6,492,410
Effect of issuance of nonvested restricted common shares	334,465	369,840
Weighted average and potential dilutive outstanding (1)	348,196,507	344,064,964
Net Income per Common Share:		
Basic	$ 0.32	$ 0.15
Diluted	$ 0.31	$ 0.15

(1) Options for 396,840 shares for the three months ended March 31, 2008 and 873,330 shares for the comparable period of 2007 (as adjusted for the stock split) were excluded from the calculations because they would have had an antidilutive effect. Additionally, 1,613 shares of restricted stock for the three months ended March 31, 2008 and 19,800 shares of restricted stock for the comparable period of 2007 (as adjusted for the stock split) were excluded from the calculations because they would have had an antidilutive effect.

(4)

ASSETS HELD FOR SALE

In November 2007, the Company entered into an agreement to sell all of the capital stock of Arkansas Western Gas Company (AWG) for $224 million plus working capital. Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144), requires that long-lived assets or disposal groups to be sold should be classified as held for sale in the period in which certain criteria are met. Accordingly, the assets and liabilities of AWG have been presented as held for sale in the March 31, 2008 and December 31, 2007 balance sheets.

The following table presents the assets and liabilities of AWG as of March 31, 2008 and December 31, 2007:

	March 31, 2008	December 31, 2007
	(in thousands)	

Current Assets:				
Cash	$	1,736	$	1,105
Accounts receivable		29,610		29,826
Inventory		14,485		23,737
Hedging asset - FAS 133		-		2,387
Deferred income tax benefit		4,504		-
Other current assets		1,638		1,822
	$	51,973	$	58,877
Long-term assets, including property, plant and equipment, net of accumulated depreciation and amortization	$	142,310	$	143,234
Current Liabilities:				
Accounts payable	$	2,742	$	3,700
Taxes payable		9,273		7,547
Deferred gas purchases		12,498		16,289
Customer deposits		7,545		7,551
Hedging liability - FAS 133		-		2,387
Other current liabilities		1,701		1,644
	$	33,759	$	39,118
Long-term Liabilities:				
Deferred income taxes	$	18,427	$	15,066
Other long-term liabilities		212		351
	$	18,639	$	15,417

(5)

DEBT

Debt balances as of March 31, 2008 and December 31, 2007 consisted of the following:

	March 31, 2008	December 31, 2007
	(in thousands)	
Current portion of long-term debt:		
7.15% Senior Notes due 2018	$ 1,200	$ 1,200

Long-term:		
Variable rate (3.91% at March 31, 2008) unsecured revolving		
credit facility	341,200	842,200
7.5% Senior Notes due 2018	600,000	-
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	35,400	35,400
Total long-term debt	1,076,600	977,600
Total debt	$ 1,077,800	$ 978,800

On January 16, 2008, the Company issued $600 million of 7.5% Senior Notes due 2018 in a private placement. The 7.5% Senior Notes are redeemable at the Company s election, in whole or in part, at any time at a redemption price equal to the greater of: (1) 100% of the principal amount of the notes to be redeemed then outstanding; and (2) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the redemption date on a semiannual basis as determined in accordance with the indenture, plus 50 basis points, plus, in either of such cases, accrued and unpaid interest to the date of redemption on the notes to be redeemed. In addition, if the Company undergoes a change of control, as defined in the indenture, holders of the 7.5% Senior Notes will have the option to require the Company to purchase all or any portion of the notes at a purchase price equal to 101% of the principal amount of the notes to be purchased plus any accrued and unpaid interest to, but excluding, the change of control date. Payment obligations with respect to the 7.5% Senior Notes are currently guaranteed by the Company s subsidiaries, SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Southwestern Energy Services (SES), which guarantees may be unconditionally released in certain circumstances. The indentures governing the 7.5% Senior Notes and the Company s other senior notes contain covenants that, among other things, restrict the ability of the Company and/or its subsidiaries to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets.

In October 2007, the Company amended its unsecured revolving credit facility increasing the borrowing capacity to $1.0 billion. The amendment also provides that the amount available under the revolving credit facility may be increased to $1.25 billion at any time upon the Company s agreement with its existing or additional lenders. 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, SEECO, SEPCO, and SES and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. At March 31, 2008, the Company s capital structure consisted of 41% debt and 59% equity and it was in compliance with the covenants of its debt agreements.

(6)

DERIVATIVES AND RISK MANAGEMENT

The Company enters into various types of derivative instruments for a portion of its projected gas and oil sales to reduce its exposure to market price volatility for natural gas and oil. At March 31, 2008, 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, FAS 149 and FAS 157 (see Note 7 below regarding the adoption of FAS 157 in the first quarter of 2008), requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Accounting for qualifying hedges allows a derivative's gains and losses to be recorded as a component of other comprehensive income. Hedges that are not elected for hedge accounting treatment or that do not meet the requirements of FAS 133 cannot be recorded as a component of other comprehensive income. The Company s hedging practices are summarized in Note 9 of the Notes to Consolidated Financial Statements in the 2007 Annual Report on Form 10-K.

At March 31, 2008, the Company's net liability recorded on the balance sheet related to its hedging activities was $269.8 million. Additionally, at March 31, 2008, the Company recorded a loss to other comprehensive income of $167.5 million related to its hedging activities which resulted in a current

deferred income tax benefit of $63.6 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 gas futures as of March 31, 2008 remain unchanged, the Company would expect to transfer an aggregate after-tax loss of approximately $120.3 million from accumulated other comprehensive income to earnings during the next 12 months. The change in accumulated other comprehensive income related to derivatives was a loss of $309.9 million ($192.1 million after tax) and a loss of $93.8 million ($58.2 million after tax) for the three months ended March 31, 2008 and 2007, respectively. The Company recorded a $7.6 million decrease in gas sales revenues during the first quarter of 2008 related to the ineffectiveness of cash flow hedges and changes in unrealized gains or losses for derivatives that were not accounted for as cash flow hedges. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the application of FAS 133.

(7)

FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company adopted Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" (FAS 157), which defines fair value, provides a framework for measuring fair value under generally accepted accounting principles (GAAP) and expands required disclosures about fair value measurements. The Company also adopted Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (FAS 159), on January 1, 2008, which allows an entity the irrevocable option to elect fair value for the initial and subsequent measurement for certain financial assets and liabilities on a contract-by-contract basis. The Company does not plan to elect to use the fair value option under FAS 159 for any of its financial instruments that are not currently measured at fair value.

FAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels. Level 1 valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority. Level 2 fair value valuations rely on quoted market information for the calculation of fair market value. Level 3 valuations are internal estimates and have the lowest priority. Per FAS 157, the Company has classified its derivatives into these levels depending upon the data relied on to determine the fair values. The Company s natural gas swaps are estimated using internal discounted cash flow calculations using the NYMEX futures index and are designated as Level 2. The fair values of collars and natural gas basis swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves or quotes obtained from counterparties to the agreements and are designated as Level 3. Assets and liabilities measured at fair value on a recurring basis are summarized below:

	March 31, 2008 (in thousands)			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets/Liabilities at Fair Value
Derivative assets	$ -	$ 3,688	$ 57,979	$ 61,667
Derivative liabilities	-	(220,017)	(111,492)	(331,509)
Total	$ -	$ (216,329)	$ (53,513)	$ (269,842)

The table below presents a reconciliation for assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the first quarter of 2008. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in management s judgment, reflect the assumptions a marketplace participant would have used at March 31, 2008.

Total Gains and Losses (Level 3 Only)

		Net Derivatives (in thousands)
Balance at January 1, 2008	$	32,767
Total gains or losses (realized/unrealized):		
Included in earnings (1)		9,333
Included in other comprehensive income (loss)		(84,378)
Purchases, Issuances and Settlements		(11,235)
Transfers in to/out of Level 3		-
Balance at March 31, 2008	$	(53,513)
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of March 31, 2008	$	(1,902)

(1) Reported in gas sales revenue in the consolidated statements of operations.

(8)

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 are expected to increase in the future as the level of production from our Fayetteville Shale properties continues to increase. Revenues for the Natural Gas Distribution segment arise from the transportation and sale of natural gas at retail by AWG. Following the consummation of the pending sale of AWG, the Company will not have any natural gas distribution operations.

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 2007 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 and corporate items.

	Exploration And Production	Midstream Services	Natural Gas Distribution	Other	Total
			(in thousands)		
Three months ended March 31, 2008:					
Revenues from external customers	$ 297,099	$ 145,523	$ 81,484	$ -	$ 524,106
Intersegment revenues	14,918	259,802	2,707	112	277,539
Operating income	165,710	10,161	11,590	49	187,510

Other income (expense)	114	-	(107)	-	7
Depreciation, depletion and amortization expense	93,306	2,037	1,718	36	97,097
Interest expense (1)	8,770	1,551	1,208	-	11,529
Provision for income taxes (1)	59,629	3,272	3,904	19	66,824
Assets	3,351,181	354,207	194,283	75,091 (2)	3,974,762 (2)
Capital investments (3)	376,514	31,445	991	908	409,858
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
Other income (expense)	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

(1)

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

(2)

Other assets include corporate assets not allocated to segments and assets for non-reportable segments.

(3)

Capital investments include an increase of $16.8 million and a reduction of $46.3 million for the three-month periods ended March 31, 2008 and 2007, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $239.1 million and $107.0 million for the first quarters of 2008 and 2007, 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 and other 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.

(9)

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, 2008		For the three months ended March 31, 2007	
	(in thousands)			
Interest payments	$	5,702	$	1,181
Income tax payments	$	-	$	-

(10)

CONTINGENCIES AND COMMITMENTS

Operating Commitments

The Company has various operating commitments in the normal course of its operations. In the first quarter of 2008, the Company exercised the first of its three options to increase the volumes to be transported on each of the two pipeline laterals and related facilities being constructed by Texas Gas Transmission, LLC for which the Company is the anchor shipper. The options exercised will allow the Company to transport up to 600,000 MMBtu per day on the Fayetteville Lateral and up to 480,000 MMBtu per day on the Greenville Lateral. Other than the increase in pipeline volume commitments, the Company has not made any new material operating commitments or modified its disclosed material commitments from those disclosed in the 2007 Annual Report on Form 10-K.

Environmental Risk

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.

Litigation

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 currently pending will not have a material effect on the results of operations or the financial position of the Company.

(11)

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 10 of the Notes to Consolidated Financial Statements included in Item 8 of the 2007 Annual Report on Form 10-K.

For the three months ended March 31, 2008 and 2007, the Company recorded compensation cost of $0.8 million and $0.7 million, respectively, in general and administrative expense related to stock options. An additional amount of $0.2 million for each of the same respective periods 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 Company also recorded a deferred tax benefit of $0.2 million related to stock options for the three months ended March 31, 2008, compared to a deferred tax benefit of $0.3 million for the comparable period in 2007. A total of $6.6 million of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods.

For the three-month periods ended March 31, 2008 and 2007, the Company recorded compensation cost of $0.9 and $0.7 million, respectively, in general and administrative expense related to prior restricted stock grants. Additional amounts of $0.7 million and $0.5 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool. As of March 31, 2008, there was $12.8 million of total unrecognized compensation cost related to nonvested shares of restricted stock.

The following tables summarize stock option activity for the first three months of 2008 and provide information for options outstanding at March 31, 2008. The number of options and exercise prices have been restated, as necessary, to reflect the two-for-one stock split effected on March 25, 2008:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2007	8,552,874	$ 4.81
Granted	14,000	27.12
Exercised	(365,356)	2.24
Forfeited or expired	-	-
Outstanding at March 31, 2008	8,201,518	$ 4.97
Exercisable at March 31, 2008	7,345,909	$ 2.84

During the first three months of 2008, there were 14,000 options granted, compared to no options granted during the first three months of 2007. The total intrinsic value of options exercised during the first three months of 2008 and 2007 was $9.4 million and $31.2 million, respectively. Associated with the exercise of stock options, the Company recorded a tax benefit of $11.5 million in the first three months of 2007. The tax benefit was recorded as an increase in additional paid-in capital.

	Options Outstanding				Options Exercisable		
Range of Exercise Prices	Options Outstanding at March 31, 2008	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at March 31, 2008	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$0.75 - $1.00	2,931,444	$ 0.88	2.3		2,931,444	$ 0.88	
$1.01 - $2.50	2,021,166	1.37	4.2		2,021,166	1.37	
$2.51 - $6.00	1,305,310	2.75	5.7		1,305,310	2.75	
$6.01 - $17.75	1,060,888	10.42	4.1		926,536	9.36	
$17.76 - $27.18	882,710	23.49	6.1		161,453	20.07	
	8,201,518	$ 4.97	4.0	$ 235,570	7,345,909	$ 2.84	$ 226,621

The following table summarizes restricted stock activity for the first quarter of 2008. The number of shares and the grant date fair values have been restated, as necessary, to reflect the two-for-one stock split effected on March 25, 2008:

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2007	791,030	$ 19.89
Granted	12,500	28.74
Vested	(17,786)	13.99
Forfeited	(7,097)	22.72
Unvested shares at March 31, 2008	778,647	$ 20.14

(12)

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, 2008 and 2007:

	Pension Benefits For the three months ended March 31,	
	2008	2007
	(in thousands)	
Service cost	$ 1,408	$ 996

Interest cost	1,210	1,060
Expected return on plan assets	(1,255)	(1,140)
Amortization of prior service cost	122	119
Amortization of net loss	174	115
Net periodic benefit cost	$ 1,659	$ 1,150

	Postretirement Benefits For the three months ended March 31,	
	2008	2007
	(in thousands)	
Service cost	$ 165	$ 104
Interest cost	77	54
Expected return on plan assets	(24)	(20)
Amortization of transition obligation	22	22
Amortization of prior service cost	3	-
Amortization of net loss	17	5
Net periodic benefit cost	$ 260	$ 165

The Company currently expects to contribute $8.1 million to the pension plans and $0.4 million to the postretirement benefit plans in 2008. As of March 31, 2008, no contributions have been made to the pension plans, and $0.1 million has been contributed to the postretirement benefit plans.

The Company also maintains a non-qualified defined contribution supplemental retirement savings plan for certain key employees whereby participants may elect to defer and contribute a portion of their compensation, as permitted by the plan. The Company maintains supplemental retirement savings plan assets that are accounted for in accordance with EITF Issue No. 97-14, Accounting for Deferred Compensation Arrangements Where Accounts are Held in a Rabbi Trust and Invested (EITF 97-14), and the underlying assets are held in a Rabbi Trust. Shares of the Company s common stock purchased under a non-qualified deferred compensation arrangement are held in a Rabbi Trust and are presented as treasury stock. As of March 31, 2008, 224,393 shares were accounted for as treasury stock, compared to 222,774 shares at December 31, 2007.

(13)

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 (in thousands) for the three-month period ended March 31, 2008 and for the year ended December 31, 2007:

Asset retirement obligation at January 1	$ 12,114	$ 10,545
Accretion of discount	124	481
Obligations incurred	914	2,236
Obligations settled/removed	(301)	(499)
Revisions of estimates	-	(649)
Asset retirement obligation at March 31, 2008 and December 31, 2007	$ 12,851	$ 12,114
Current liability	729	720
Long-term liability	12,122	11,394
Asset retirement obligation at March 31, 2008 and December 31, 2007	$ 12,851	$ 12,114

(14)

INVENTORY

Inventory recorded in current assets includes $11.5 million at March 31, 2008, and $25.0 million at December 31, 2007, for gas in underground storage owned by the Company s E&P segment, and $10.5 million at March 31, 2008, and $8.1 million at December 31, 2007, for tubulars and other equipment used in the Company s E&P segment. Additionally, the Natural Gas Distribution segment has current gas in underground storage of $12.2 million at March 31, 2008, and $21.6 million at December 31, 2007, that is classified in the balance sheets as Current Assets Held for Sale.

Other assets includes $15.6 million at March 31, 2008, and $16.7 million at December 31, 2007, for non-current inventory held by the Midstream Services segment consisting primarily of tubulars that will be used to construct gathering systems for the Fayetteville Shale play.

(15)

SUBSEQUENT EVENTS

On April 3, 2008, the Company announced that its wholly-owned subsidiary had entered into a definitive purchase and sale agreement with XTO Energy Inc. for the sale of certain oil and gas leases, wells and gathering equipment held by the Company in its Fayetteville Shale play for approximately $519.6 million in cash. The sale included 55,631 net acres, or approximately 6% of the Company s approximately 906,700 net acres in the play as of December 31, 2007, and approximately 10.5 MMcf per day of production from the Fayetteville Shale as of March 17, 2008. The acreage is located in the southeast portion of the Company's focus area, and the transaction is scheduled to close in the second quarter of 2008.

(16)

NEW ACCOUNTING PRONOUNCEMENTS

In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position FAS 157-2, Effective Date of FASB Statement No. 157 (FSP FAS 157-2). FSP FAS 157-2 delays the effective date of FAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). FSP FAS 157-2 is effective for the Company s fiscal year beginning January 1, 2009. The adoption of FSP FAS 157-2 is not expected to have a material impact on the Company s consolidated financial statements**.**

In March, 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (FAS 161). FAS 161 requires enhanced disclosures for derivative instruments and hedging activities that include how and why an entity uses derivatives, how instruments and the related hedged items are accounted for under FAS 133 and related interpretations, and how derivative instruments and related hedged items affect the entity s financial position, results of operations and cash flows. FAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company is currently reviewing the standard to assess the impact of the adoption of FAS 161.

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 2007 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three-month periods ended March 31, 2008 and 2007. 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 2007 Annual Report on Form 10-K.

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in our forward-looking statements for many reasons, including the risks described in the Cautionary Statement About Forward-Looking Statements in the forepart of this Form 10-Q, in Item 1A, "Risk Factors" in Part I and elsewhere in our 2007 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 consolidated financial statements and the related notes included in this Form 10-Q.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily focused on the exploration and production of natural gas within the United States. Our operations primarily are located in Arkansas, Oklahoma and Texas. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas gathering and marketing businesses, which we refer to collectively as our Midstream Services. We operate principally in three segments: Exploration and Production (E&P), Midstream Services and Natural Gas Distribution. Following the consummation of the pending sale of our utility subsidiary, Arkansas Western Gas Company (AWG), which is subject to certain closing conditions and regulatory approvals and is expected to close approximately mid-year 2008, we will cease to have any natural gas distribution operations. The assets and liabilities of AWG have been reclassified as held for sale in our March 31, 2008 and December 31, 2007 balance sheets, however, the results of operations for AWG continue to be consolidated in the statements of operations and are not presented as discontinued operations. We refer you to Note 4 to the consolidated financial statements included in this Form 10-Q for additional information.

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 2008, our gas and oil production increased to 39.1 Bcfe, up 71% from the first quarter of 2007. The increase in 2008 production primarily resulted from a significant increase in production from our Fayetteville Shale play as a result of our ongoing development program. The average price realized for our gas production, including the effects of hedges, increased approximately 15% to $7.70 per Mcf for the three months ended March 31, 2008, as compared to the same period last year.

We reported net income of $109.0 million in the first quarter of 2008, or $0.31 per share on a fully diluted basis, up 114% from the prior year, due to increased production volumes in our E&P segment and higher realized natural gas prices, which were only partially offset by increased operating costs and expenses. As a result, operating income for our E&P segment was $165.7 million for the first quarter of 2008, up 123% from the comparable period of 2007. Operating income for our Midstream Services segment was $10.2 million for the first quarter of 2008, up from approximately breakeven in the first quarter of 2007, due primarily to an increase in gathering revenues related to our Fayetteville Shale play. Operating income for our Natural Gas Distribution segment increased 24% to $11.6 million for the three months ended March 31, 2008, primarily due to colder weather and a rate increase implemented in August 2007.

Our capital investments increased approximately 25% to $409.9 million for the first quarter of 2008, of which $376.5 million was invested in our E&P segment.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended March 31, 2008	2007
Revenues (in thousands)	$312,017	$161,261

Operating income (in thousands)	$165,710	$74,310
Gas production (MMcf)	38,205	21,886
Oil production (MBbls)	142	167
Total production (MMcfe)	39,057	22,891
Average gas price per Mcf, including hedges	$7.70	$6.71
Average gas price per Mcf, excluding hedges	$7.46	$6.19
Average oil price per Bbl	$96.55	$55.17
Average unit costs per Mcfe:		
Lease operating expenses	$0.77	$0.74
General & administrative expenses	$0.42	$0.47
Taxes, other than income taxes	$0.16	$0.27
Full cost pool amortization	$2.30	$2.24

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up 93% for the three months ended March 31, 2008, compared to the same period in 2007, primarily due to increased production volumes and higher gas and oil prices realized for our production. We expect our production volumes to continue to increase 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 22, 2008, we have hedged 94.5 Bcf of our remaining 2008 gas production, 123.0 Bcf of 2009 gas production and 42.0 Bcf of 2010 gas production to limit our exposure to price fluctuations. Revenues for the first three months of 2008 and 2007 also included pre-tax gains of $2.5 million and $5.1 million, respectively, related to the sale of gas in storage inventory.

Operating Income. Operating income from our E&P segment was up 123% to $165.7 million for the first quarter of 2008 from $74.3 million for the same period in 2007. The increase in operating income was a result of the increase in revenues, partially offset by an increase in operating costs and expenses.

Production. Gas and oil production during the first quarter of 2008 was up 16.2 Bcfe, or approximately 71%, to 39.1 Bcfe, as compared to the prior year period, primarily due to an increase in production from our Fayetteville Shale play as a result of our ongoing development program. Our total gas production was up approximately 75% to 38.2 Bcf for the first quarter of 2008, as compared to the prior period, and represented approximately 98% of our total equivalent production. Net production from the Fayetteville Shale was 23.6 Bcf in the first quarter of 2008, up from 8.2 Bcf in the first quarter of 2007. On April 3, 2008, we announced the sale of 55,631 net acres, or approximately 6% of our total net acres in the Fayetteville Shale play, for $519.6 million. Production from the acreage sold was 10.5 MMcf per day at March 17, 2008. This transaction is scheduled to close in the second quarter of 2008.

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 Notes 6 and 7 to the consolidated financial statements included in this Form 10-Q for additional discussion). The average price realized for our gas production, including the effects of hedges, increased approximately 15% to $7.70 per Mcf for the three months ended March 31, 2008, 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 positive effects of our price hedging activities. Our hedging activities increased the average gas price $0.24 per Mcf during the first quarter of 2008, compared to an increase of $0.52 per Mcf during the first quarter of 2007. We had protected approximately 60% of our production in the first quarter of 2008 from the impact of widening basis differentials and have also protected approximately 70% of our anticipated gas production for the remainder of the year 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 2008 was approximately $0.57 lower than average NYMEX spot prices, which represented the average locational basis differential.

As of April 22, 2008, we have NYMEX commodity price hedges in place for 94.5 Bcf of our remaining 2008 gas production. For our 2009 and 2010 future gas production, we have hedges in place on 123.0 Bcf and 42.0 Bcf, respectively. Additionally, we have basis swaps on 60.6 Bcf for the remainder of 2008, and on 6.3 Bcf for 2009, in order to reduce the effects of changes in market differentials on prices we receive.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.77 for the first quarter of 2008, as compared to $0.74 per Mcfe for the same period in 2007. The increase was primarily due to increased production from our Fayetteville Shale operations which has higher per unit operating costs than our other focus areas. We continue to expect our per unit operating cost for this segment to range between $0.85 and $0.90 per Mcfe for 2008.

General and administrative expenses per Mcfe for the first quarter of 2008 decreased 11% to $0.42 per Mcfe compared to $0.47 per Mcfe for the same period in 2007 primarily due to the effects of our increased production volumes which more than offset increased compensation and related costs. In total, general and administrative expenses for our E&P segment were $16.6 million in the first quarter of 2008, compared to $10.8 million in the first quarter of 2007. The increase in total general and administrative costs was due primarily to increased payroll and related costs associated with the expansion of our E&P operations due to the Fayetteville Shale play since the first quarter of 2007. We expect our cost per unit for general and administrative expenses in 2008 to range between $0.42 and $0.47 per Mcfe.

Our full cost pool amortization rate averaged $2.30 per Mcfe for the first quarter of 2008, up 3%, compared to the same period in 2007. Our full cost pool amortization rate increased due to increased capital investments and future development costs relative to reserve additions, including revisions, partially offset by an increase in reserve volumes. The amortization rate is impacted by 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, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to 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 other factors, including but not limited to the uncertainty of the amount of future reserves attributed to our Fayetteville Shale play. Unevaluated costs excluded from amortization were $455.7 million at March 31, 2008, compared to $178.3 million at March 31, 2007, and $372.4 million at December 31, 2007. The increase in unevaluated costs since March 31, 2007, resulted primarily from an increase in our undeveloped leasehold acreage and seismic costs related to our Fayetteville Shale play and our increased drilling activity.

Taxes other than income taxes per Mcfe decreased to $0.16 for the first quarter of 2008, compared to $0.27 for the same period in 2007, and vary from period to period due to changes in severance and ad valorem taxes that primarily result from the mix of our production volumes and fluctuations in commodity prices. Additionally, we accrued $1.8 million in the first quarter of 2008 for severance tax refunds related to our East Texas production, compared to $0.1 million in the first quarter of 2007. In April 2008, the Arkansas Legislature passed an initiative to increase the severance tax on natural gas produced within the state to a base rate of 5%, subject to certain periods of reduced rates for high-cost gas wells, new discovery gas wells and gas wells that produce below a specified level. The new tax rates will become effective January 1, 2009, and will negatively impact our results of operations.

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

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, 2008, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At March 31, 2008, the ceiling value of our reserves was calculated based upon quoted market prices of $9.37 per Mcf for Henry Hub gas and $98.00 per barrel for West Texas Intermediate oil, adjusted for market differentials. Cash flow hedges of gas production in place at March 31, 2008 decreased the calculated ceiling value by approximately $99.7 million (net of tax). We had approximately 259.5 Bcf of future gas production hedged at March 31, 2008. Decreases in market

prices from March 31, 2008 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs could result in future ceiling test impairments.

Midstream Services

	For the three months ended March 31,	
	2008	2007
	($ in thousands, except volumes)	
Revenues - marketing	$385,721	$173,651
Revenues - gathering	$19,604	$4,938
Gas purchases - marketing	$383,060	$171,679
Operating costs and expenses	$12,104	$6,899
Operating income	$10,161	$11
Gas volumes marketed (Bcf)	50.1	27.1
Gas volumes gathered (Bcf)	38.5	10.7

Revenues and Operating Income

Revenues. Revenues from our Midstream Services segment were up 127% in the first quarter of 2008, as compared to the prior year period. The increases in first quarter revenues resulted from increases in volumes marketed and increased gathering revenues, primarily relating to the Fayetteville Shale play. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Midstream Services had gathering revenues of $19.6 million in the first quarter of 2008, compared to $4.9 million for the comparable period of 2007. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as reserves related to our Fayetteville Shale play are developed and production increases.

Operating Income. Operating income from our Midstream Services segment increased significantly in the first quarter of 2008, as compared to the same period of 2007, primarily as a result of the increases in gathering revenues from the Fayetteville Shale play, partially offset by increased operating costs and expenses. The margin generated from natural gas marketing activities was $2.7 million for the first quarter of 2008, up from $2.0 million for the same period of 2007. Margins may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increase in volumes marketed in the first quarter of 2008, as compared to the same period in 2007, resulted from marketing our increased production volumes, primarily related to our Fayetteville Shale play, and volumes for third parties in areas where we have production. Of the total volumes marketed, production from our E&P subsidiaries accounted for 98% in the first quarter of 2008 and 85% in the first quarter of 2007. 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, "Quantitative and Qualitative Disclosures about Market Risks" in this Form 10-Q for additional information.

Natural Gas Distribution

	For the three months ended March 31,	
	2008	2007
Revenues (in thousands>	$84,191	$76,994
Gas purchases (in thousands)	$58,657	$54,217
Operating costs and expenses (in thousands)	$13,944	$13,396
Operating income (in thousands)	$11,590	$9,381
Sales and end-use transportation deliveries (Bcf)	10.2	9.5

Sales customers at period-end	153,875	152,751
Average sales rate per Mcf	$10.97	$10.68
Heating weather - degree days	2,197	1,941
Percent of normal	100%	89%

In November 2007, we entered a definitive agreement for the sale of all capital stock of our utility subsidiary, AWG, to SourceGas LLC for $224 million plus working capital. The transaction is subject to certain closing conditions and regulatory approvals and is expected to close by mid-year 2008. The assets and liabilities associated with AWG have been reclassified as held for sale as of March 31, 2008 and December 31, 2007. Upon the consummation of the sale, we will cease to have any natural gas distribution operations.

Revenues and Operating Income

Revenues increased 9% for the first quarter of 2008, compared to the prior year period. The increase in first quarter revenues resulted primarily from an increase volumes delivered and the rate increase implemented in August 2007. Weather was normal during the first three months of 2008 and was 11% colder than the same period in 2007.

Operating income for our Natural Gas Distribution segment increased 24% in the first quarter of 2008, compared to the prior year period. The increase in first quarter of 2008 operating income resulted primarily from the increase in revenues.

Deliveries and Rates

Deliveries were up 7% in the first quarter of 2008, as compared to the same period in 2007, due to the colder weather. The average sales rate per Mcf increased slightly during the first quarter of 2008 reflecting the change in natural gas prices and the impact of incremental volumes delivered.

Our utility segment hedged 2.0 Bcf of derivative gas purchases during the first three months of 2008 which had the effect of increasing its total gas supply cost by $1.2 million. In the first three months of 2007, our utility hedged 3.1 Bcf of its gas supply, which increased its total gas supply cost by $6.6 million. See Notes 6 and 7 to the consolidated financial statements included in, 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 three months of 2008, operating costs and expenses (exclusive of purchased gas costs) for this segment were slightly higher than the comparable period of the prior year due primarily to increased payroll and other operating costs.

Other Revenues

Other revenues for the first three months of 2008 and 2007 included pre-tax gains of $2.5 million and $5.1 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, increased to $11.5 million for the first quarter of 2008, compared to $1.5 million for the same period in 2007, due to increased debt levels resulting from our increased level of capital investments. We capitalized $6.2 million of interest in the first three months of 2008, compared to $3.0 million for the same period in 2007, as our costs excluded from amortization in the E&P segment increased to $455.7 million at March 31, 2008, up from $178.3 million at March 31, 2007.

Income Taxes

Our provision for deferred income taxes was an effective rate of 38.0% for both the first three months of 2008 and 2007. Any 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 incurred pension costs of $1.9 million in the first quarter of 2008 for our pension and other postretirement benefit plans, compared to $1.3 million for the same period of 2007. The increase was primarily the result of an increase in our number of employees. 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 $8.5 million to our pension and other postretirement plans in 2008. As of March 31, 2008, no contributions have been made to the pension plans, and $0.1 million has been contributed to the postretirement benefit plans. For further information regarding our pension plans, we refer you to Note 12 to the consolidated financial statements included in this Form 10-Q.

Stock-Based Compensation

We recognized expense of $1.7 million and capitalized $0.9 million to the full cost pool for stock-based compensation in the first quarter of 2008, compared to $1.5 million expensed and $0.6 million capitalized to the full cost pool for the first quarter of 2007. We refer you to Note 11 to the consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

Adoption of Accounting Principles

During the first quarter of 2008, we adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements (FAS 157). FAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement applies to other accounting pronouncements that require or permit fair value measurements, and is effective for financial statements issued for fiscal years beginning after November 15, 2007. In addition to required disclosures, FAS 157 also requires companies to evaluate current measurement techniques. The adoption of FAS 157 had no material impact on our results of operations and financial condition. See Note 7 to the consolidated financial statements included in this Form 10-Q for further information.

During the first quarter of 2008, we adopted Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (FAS 159). FAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value and applies to other accounting pronouncements that require or permit fair value measurements. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of FAS 159 had no impact on our results of operations and financial condition.

In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position FAS 157-2, Effective Date of FASB Statement No. 157 (FSP FAS 157-2). FSP FAS 157-2 delays the effective date of FAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). FSP FAS 157-2 is effective for our fiscal year beginning January 1, 2009. The adoption of FSP FAS 157-2 is not expected to have a material impact on our results of operations and financial condition.

In March 2008, the Financial Accounting Standards Board issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (FAS 161). FAS 161 requires enhanced disclosures for derivative instruments and hedging activities that include how and why an entity uses derivatives, how these instruments and the related hedged items are accounted for under FAS 133 and related interpretations, and how derivative instruments and related hedged items affect the entity s financial position, results of operations and cash flows. FAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently reviewing the standard to assess the impact of the adoption of FAS 161.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our unsecured revolving credit facility (discussed below under "Financing Requirements") and funds accessed through debt and equity markets as our primary sources of liquidity. We may borrow up to $1.0 billion under our revolving credit facility from time to time. The amount available under our revolving credit facility may be increased up to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of March 31, 2008, we had $341.2 million outstanding under our revolving credit facility. At December 31, 2007, we had $842.2 million outstanding under our revolving credit facility.

On January 16, 2008, we completed a private placement of $600 million of 7.5% Senior Notes due 2018 (discussed below under Financing Requirements). Net proceeds of approximately $591 million from the offering were used to pay outstanding indebtedness under our revolving credit facility.

Net cash provided by operating activities increased 131% to $297.1 million in the first three months of 2008, compared to the same period in 2007, due primarily to an increase in net income and adjustments for non-cash expenses. During the first three months of 2008, requirements for our capital investments were funded from cash provided by operating activities and our revolving credit facility, which was partially repaid using the net proceeds from the 7.5% Senior Notes.

On April 3, 2008, we announced the sale of 55,631 net acres in the Fayetteville Shale play for $519.6 million. This transaction is scheduled to close in the second quarter of 2008. After-tax proceeds from the sale will be used to pay down our revolving credit facility.

At March 31, 2008, our capital structure consisted of 41% debt and 59% equity. We believe that our operating cash flow, borrowings under our revolving credit facility and the expected proceeds from the pending sales of the Fayetteville Shale acreage and our utility, AWG, and any other E&P asset divestitures we might make will be adequate to meet our capital and operating requirements for 2008.

Our cash flow from operating activities is highly dependent upon the 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 Notes 6 and 7 to the consolidated 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 available cash flow.

Capital Investments

Our capital investments increased to $409.9 million for the first three months of 2008, compared to $327.3 million for the same period last year. Our E&P segment investments were $376.5 million during the first three months of 2008 and were $301.2 million for the comparable period in 2007. Our capital investments for 2008 are currently expected to be approximately $1.46 billion, consisting of $1.33 billion for E&P, $101 million for Midstream Services and $25 million for Natural Gas Distribution improvements and general purposes. We expect to allocate approximately $1.0 billion of our 2008 E&P capital to our Fayetteville Shale play. Our 2008 capital investment program is expected to be funded through cash flow from operations, borrowings under our credit facility and the expected after-tax proceeds from the sale of AWG, the sale of the Fayetteville Shale acreage discussed above and potential sales of certain other E&P assets. We may adjust the level of 2008 capital investments dependent upon our level of cash flow generated from operations and asset sales and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $1,077.8 million at March 31, 2008, compared to $978.8 million at December 31, 2007. On October 12, 2007, we amended our unsecured revolving credit facility to, among other things, increase the current borrowing capacity to $1.0 billion. Pursuant to the amendment, the amount available under the revolving credit facility may be increased to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of March 31, 2008, we had $341.2 million outstanding under our revolving credit facility compared to $842.2 million outstanding as of December 31, 2007. As discussed more fully below, in January 2008, we issued $600 million of 7.5% Senior Notes due 2018, the net proceeds of which were used to repay amounts outstanding under our revolving credit facility. The interest rate on the credit 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, SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Southwestern Energy Services Company (SES) 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. Any future downgrades in our public debt ratings could increase our cost of funds under the 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 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, 2008. 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 may have to decrease our capital investment plans.

On January 16, 2008, we issued $600 million of 7.5% Senior Notes due 2018 in a private placement, which are rated BB+ by Standard and Poor s and Ba2 by Moody s. The 7.5% Senior Notes are redeemable at our election, in whole or in part, at any time at a redemption price equal to the greater of: (i) 100% of the principal amount of the notes to be redeemed then outstanding; and (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed as determined in accordance with the indenture, plus 50 basis points. Any redemption is also subject to payment of accrued and unpaid interest to the date of redemption. In addition, if we undergo a change of control as defined in the indenture, holders of the 7.5% Senior Notes will have the option to require us to purchase all or any portion of the notes at a purchase price equal to 101% of the principal amount of the notes to be purchased plus any accrued and unpaid interest to, but excluding, the change of control date. The 7.5% Senior Notes are currently guaranteed by our subsidiaries SEECO, SEPCO and SES, which guarantees may be unconditionally released in certain circumstances. The indentures governing the 7.5% Senior Notes and our other senior notes contain covenants that, among other things, restrict the ability of us and/or our subsidiaries to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets.

At March 31, 2008, our capital structure consisted of 41% debt and 59% equity. Our capital structure at March 31, 2008 would have been 38% debt and 62% equity without consideration of accumulated other comprehensive losses in shareholders equity related to our commodity hedge position and our pension liability. Depending upon the level of cash proceeds received from our planned asset sales and our operating results, our total debt could decline to 25% to 30% of our capital structure by year end. Stockholders equity at March 31, 2008, includes an accumulated other comprehensive loss of $167.5 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 $11.1 million related to

changes in our pension liability. The amount recorded for FAS 133 is based on current market values of our hedges at March 31, 2008, 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.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 80% of our expected 2008 gas production. The amount of long-term debt we incur will be dependent upon commodity prices, our capital investment plans and the actual proceeds from the pending sales of our utility and the Fayetteville Shale acreage as well as any other E&P asset divestitures. If commodity prices remain at or near their current levels throughout 2008, assuming that we do not complete the pending sales or the divestitures of any other E&P assets, our long-term debt would significantly increase in 2008. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital investments.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. On January 16, 2008, the Company issued $600 million of 7.5% Senior Notes due 2018 in a private placement. In the first quarter of 2008, we exercised the first of our three options to increase the volumes to be transported on each of the two pipeline laterals and related facilities being constructed by Texas Gas Transmission, LLC for which we are the anchor shipper. The options exercised will allow us to transport up to 600,000 MMBtu per day on the Fayetteville Lateral and up to 480,000 MMBtu per day on the Greenville Lateral. Other than the Senior Note issuance and the increase in pipeline volume commitments, there have been no material changes to our contractual obligations from those disclosed in our 2007 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. As a result of actuarial data, and assuming the closing of the sale of AWG by mid-year, we expect to record expenses of $7.7 million in 2008 for these plans, of which $1.9 million has been recorded in the first three months of 2008. At March

31, 2008, we recognized a liability of $16.0 million as a result of the underfunded status of our pension and other postretirement benefit plans, compared to a liability of $14.6 million at December 31, 2007. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 12 to the consolidated financial statements in this Form 10-Q.

We are subject to litigation and claims (including with respect to environmental matters) 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.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described above. We had negative working capital of $254.9 million at March 31, 2008, and $67.6 million at December 31, 2007. Current assets increased at March 31, 2008, compared to current assets at December 31, 2007, primarily due to an increase in our current deferred income tax benefit related to our hedging activities. Current liabilities increased $221.3 million primarily due to an increase in our current hedging liability. Both changes reflect a significant increase in commodity prices for natural gas at March 31, 2008.

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 7.9 Bcf at $3.48 per Mcf at March 31, 2008, compared to 10.1 Bcf at $4.05 per Mcf at December 31, 2007.

The gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment's contractual commitments, including delivery to customers of AWG, especially during periods of colder weather. As a result, demand fees paid by AWG to our E&P subsidiaries, 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 our customers and their dispersion across geographic areas. No single customer accounted for greater than 8% of accounts receivable at March 31, 2008. In addition, see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At March 31, 2008, we had $1,077.8 million of total debt with an average interest rate of 6.35%. Our revolving credit facility has a floating interest rate (3.91% at March 31, 2008). At March 31, 2008, we had $341.2 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 Midstream Services segment, and to hedge the purchase of gas in our Natural Gas Distribution 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 relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are periodically reviewed to limit our credit risk exposure.

Exploration and Production

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 gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At March 31, 2008, the fair value of our financial instruments related to natural gas production was a $270.6 million liability.

	Volume	Weighted Average Price to be Swapped ($)	Weighted Average Floor Price ($)	Weighted Average Ceiling Price ($)	Weighted Average Basis Differential ($)	Fair Value at March 31, 2008 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2008	64.5	8.37	-	-	-	(117.4)
2009	76.0	8.30	-	-	-	(91.7)

2010	28.0	8.76	-	-	-	(7.2)
Costless Collars:						
2008	30.0	-	7.50	10.60	-	(31.0)
2009	47.0	-	8.38	10.85	-	(28.4)
2010	14.0	-	8.29	10.57	-	(1.1)
Basis Swaps:						
2008	54.3	-	-	-	(0.42)	4.3
2009	3.6	-	-	-	(0.44)	0.3
Matched-Basis Swaps:						
2008	4.5	-	-	-	(0.71)	1.6

At March 31, 2008, we had outstanding fixed-price basis differential swaps on 4.5 Bcf of 2008 gas production that qualified for hedge treatment. At March 31, 2008, we also had outstanding fixed-price basis differential swaps on 54.3 Bcf of 2008 and 3.6 Bcf of 2009 gas production that did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gas and oil sales. For the three months ended March 31, 2008, we recorded an unrealized gain of $5.4 million related to the differential swaps that did not qualify for hedge accounting treatment and a $13.6 million loss related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our hedge ineffectiveness results from changes at the end of a reporting period in the price differentials between the index price of the derivative contract, which is primarily a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged. As of April 22, 2008, we have basis-protected an additional 4.5 Bcf of future gas production subsequent to the end of the quarter.

At December 31, 2007, we had outstanding natural gas price swaps on total notional volumes of 55.7 Bcf in 2008 and 56.0 Bcf in 2009 for which we will receive fixed prices ranging from $7.29 to $9.98 per MMBtu. At December 31, 2007, we had outstanding fixed price basis differential swaps on 8.0 Bcf of 2008 gas production that qualified for hedge treatment and outstanding fixed price basis differential swaps on 66.8 Bcf of 2008 and 2009 gas production that did not qualify for hedge treatment.

At December 31, 2007, we had collars in place on notional volumes of 48.0 Bcf in 2008 and 23.0 Bcf in 2009. The 48.0 Bcf in 2008 had an average floor and ceiling price of $7.92 and $11.60 per MMBtu, respectively. The 23.0 Bcf in 2009 had an average floor and ceiling price of $8.09 and $10.91 per MMBtu, respectively.

Midstream Services

At March 31, 2008, our Midstream Services segment had outstanding fair value hedges in place on 2.3 Bcf and 0.5 Bcf of gas for 2008 and 2009, respectively. These hedges are a mixture of fixed-price swap purchases and sales relating to our gas marketing activities. These hedges have contract months from April 2008 through March 2009 and have a net fair value liability of $2.6 million as of March 31, 2008.

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 submission 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 level of 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, 2008, and provided a level of reasonable assurance with respect to financial statement preparation and presentation. There were no changes in our internal control over financial reporting during the three months ended March 31, 2008 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.

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 2007 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.

(4.1)

Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee, dated as of January 16, 2008 (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed on January 17, 2008).

(4.2)

Form of the Notes (included as an exhibit to the Indenture incorporated by reference as Exhibit 4.1 to this Form 10-Q).

(4.3)

Registration Rights Agreement between Southwestern Energy Company and the Initial Purchasers thereunder, dated as of January 16, 2008 (Incorporated by reference to Exhibit 4.3 to the Registrant s Current Report on Form 8-K filed on January 17, 2008).

(10.1)

Sales Agreement between SEECO, Inc. and XTO Energy Inc., dated April 3, 2008.

(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 28, 2008

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