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, 2009**

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 registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 North Sam Houston Parkway East, 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☒ No☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ 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.

Large accelerated filer ☒ 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 ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	Outstanding as of April 24, 2009
Common Stock, Par Value $0.01 (including associated stock purchase rights)	343,636,807

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2009

PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

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," "target" or similar expressions.

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

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- 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;
- our ability to fund our planned capital investments;
- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;

- the impact of federal, state and local government regulation, including any increase in severance taxes;
- 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;
- our future property acquisition or divestiture activities;
- the effects of weather;
- increased competition;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties, and;
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission ("SEC").

We caution you that the 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, 2008 (the "2008 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.

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	For the three months ended March 31, 2009	For the three months ended March 31, 2008
	(in thousands, except share/per share amounts)	
Operating Revenues:		
Gas sales	$ 369,429	$ 360,671
Gas marketing	154,801	137,227
Oil sales	1,182	13,713
Gas gathering	16,563	8,286
Other	(1,158)	4,209
	540,817	524,106
Operating Costs and Expenses:		
Gas purchases – midstream services	149,180	132,452
Gas purchases – gas distribution	—	51,895
Operating expenses	27,172	23,996
General and administrative expenses	23,709	23,740
Depreciation, depletion and amortization	124,228	97,097
Impairment of natural gas and oil properties	907,812	—
Taxes, other than income taxes	9,208	7,416
	1,241,309	336,596
Operating Income (Loss)	(700,492)	187,510
Interest Expense:		
Interest on debt	14,185	17,086
Other interest charges	659	648
Interest capitalized	(11,160)	(6,205)
	3,684	11,529
Other Income	365	7
Income (Loss) Before Income Taxes	(703,811)	175,988
Provision (Benefit) for Income Taxes:		
Current	(35,500)	—
Deferred	(235,459)	66,824
	(270,959)	66,824
Net income (loss)	(432,852)	109,164
Less: net income (loss) attributable to noncontrolling interest	(22)	135
Net Income (Loss) Attributable to Southwestern Energy	$ (432,830)	$ 109,029
Earnings Per Share:		
Net income (loss) attributable to Southwestern Energy stockholders - Basic	$ (1.26)	$ 0.32
Net income (loss) attributable to Southwestern Energy stockholders - Diluted	$ (1.26)	$ 0.31
Weighted Average Common Shares Outstanding:		
Basic	342,570,995	341,064,247
Diluted	342,570,995	348,196,507

See the accompanying notes which are an integral part of these unaudited condensed consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2009	December 31, 2008
ASSETS	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 82,322	$ 196,277
Accounts receivable	209,834	254,557
Inventories	35,345	50,377
Hedging asset	456,611	343,320
Other	69,080	44,734
Total current assets	853,192	889,265
Property and Equipment:		
Gas and oil properties (using the full cost method), including costs excluded from amortization of $605.5 million in 2009 and $540.6 million in 2008	5,287,126	4,836,077
Gathering systems	392,405	341,474
Gas in underground storage	13,349	13,349
Other	147,804	138,014
Total property and equipment	5,840,684	5,328,914
Less: Accumulated depreciation, depletion and amortization	2,648,330	1,615,307
Property and equipment, net	3,192,354	3,713,607
Other Assets	183,030	157,286
TOTAL ASSETS	$ 4,228,576	$ 4,760,158
LIABILITIES AND EQUITY		
Current Liabilities:		
Short-term debt	$ 61,200	$ 61,200
Accounts payable	457,534	464,145
Taxes payable	20,000	31,951
Interest payable	11,657	20,857
Advances from partners	104,082	70,603
Hedging liability	4,248	10,899
Current deferred income taxes	172,632	122,448
Other	12,682	10,758
Total current liabilities	844,035	792,861
Long-Term Debt	674,200	674,200
Other Liabilities:		
Deferred income taxes	489,885	721,707
Long-term hedging liability	2,854	5,934
Pension and other postretirement liabilities	14,944	15,436
Other long-term liabilities	28,334	32,057
	536,017	775,134
Commitments and Contingencies		
Equity:		
Southwestern Energy stockholders' equity		
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 343,633,507 shares in 2009 and 343,624,956 in 2008	3,436	3,436
Additional paid-in capital	815,362	811,492
Retained earnings	1,017,147	1,449,977
Accumulated other comprehensive income	332,551	247,665
Common stock in treasury, 202,624 shares in 2009 and 225,050 in 2008	(4,283)	(4,740)
Total Southwestern Energy stockholders' equity	2,164,213	2,507,830
Noncontrolling interest	10,111	10,133
Total equity	2,174,324	2,517,963
TOTAL LIABILITIES AND EQUITY	$ 4,228,576	$ 4,760,158

See the accompanying notes which are an integral part of these
unaudited condensed consolidated financial statements.

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

	For the three months ended March 31,	
	2009	2008
	(in thousands)	
Cash Flows From Operating Activities		
Net Income (loss)	$ (432,852)	$ 109,164
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	124,647	97,635
Impairment of natural gas and oil properties	907,812	—
Deferred income taxes	(235,459)	66,824
Impairment of natural gas inventory	4,283	—
Unrealized loss on derivatives	1,849	7,636
Stock-based compensation expense	2,275	2,458
Change in assets and liabilities:		
Accounts receivable	44,723	(39,007)
Inventories	(2,099)	21,218
Accounts payable	7,226	13,156
Taxes payable	(11,952)	3,181
Interest payable	(9,200)	11,441
Advances from partners and customer deposits	33,479	1,193
Other assets and liabilities	(27,437)	2,188
Net cash provided by operating activities	407,295	297,087
Cash Flows From Investing Activities		
Capital investments	(480,483)	(391,029)
Other	(4,370)	462
Net cash used in investing activities	(484,853)	(390,567)
Cash Flows From Financing Activities		
Payments on revolving long-term debt	—	(927,400)
Borrowings under revolving long-term debt	—	426,400
Proceeds from issuance of long-term debt	—	600,000
Debt issuance costs and revolving credit facility costs	—	(8,883)
Change in bank drafts outstanding	(36,400)	2,919
Proceeds from exercise of common stock options	3	818
Net cash provided by (used in) financing activities	(36,397)	93,854
Increase (decrease) in cash and cash equivalents	(113,955)	374
Cash and cash equivalents at beginning of year (1)	196,277	1,832
Cash and cash equivalents at end of period (1)	$ 82,322	$ 2,206

(1) Cash and cash equivalents at the beginning of the year for 2008 and at March 31, 2008 include $1.1 million and $1.7 million, respectively, classified as "held for sale." See Note 4 for additional information.

See the accompanying notes which are an integral part of these unaudited condensed consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Southwestern Energy Stockholders								
	Common Stock								
	Shares Issued	Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Common Stock in Treasury	Noncontrolling Interest	Total
					(in thousands)			
Balance at December 31, 2008	343,625	$ 3,436	$ 811,492	$1,449,977	$ 247,665	$ (4,740)	$ 10,133	$ 2,517,963
Comprehensive income (loss):								
Net loss	—	—	—	(432,830)	—	—	(22)	(432,852)
Change in value of derivatives	—	—	—	—	84,690	—	—	84,690
Change in value of pension and other postretirement liabilities	—	—	—	—	196	—	—	196
Total comprehensive loss							(22)	(347,966)
Stock-based compensation	—	—	3,663	—	—	—	—	3,663
Exercise of stock options	2	—	3	—	—	—	—	3
Issuance of restricted stock	9	—	—	—	—	—	—	—
Cancellation of restricted stock	(2)	—	—	—	—	—	—	—
Treasury stock – non-qualified plan	—	—	204	—	—	457	—	661
Balance at March 31, 2009	343,634	$ 3,436	$ 815,362	$1,017,147	$ 332,551	$ (4,283)	$ 10,111	$ 2,174,324

See the accompanying notes which are an integral part of these
unaudited condensed consolidated financial statements.

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

	For the three months ended March 31, 2009	For the three months ended March 31, 2008
	(in thousands)	
Net income (loss)	$ (432,852)	$ 109,164
Change in value of derivatives:		
Current period reclassification to earnings, net of ($53.6) and ($7.2) million in taxes	(84,553)	(11,712)
Current period ineffectiveness, net of ($0.5) and $5.2 million in taxes	(719)	8,459
Current period change in derivative instruments, net of $107.8 and ($115.8) million in taxes	169,962	(188,882)
Total change in value of derivatives	84,690	(192,135)
Current period change in value of pension and other postretirement liabilities, net of $0.1 and $0.1 million in taxes	196	209
Comprehensive income (loss)	(347,966)	(82,762)
Less: comprehensive income (loss) attributable to the noncontrolling interest	(22)	135
Comprehensive income (loss) attributable to Southwestern Energy	$ (347,944)	$ (82,897)

See the accompanying notes which are an integral part of these
unaudited condensed consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) BASIS OF PRESENTATION

Southwestern Energy Company (including its subsidiaries, collectively, the "Company," "Southwestern," "we," "us," "its," and "our") is an independent energy company primarily focused on the exploration and production of natural gas. The Company engages in natural gas and oil exploration and production and natural gas gathering and marketing through its subsidiaries. Southwestern's exploration and production ("E&P") activities are currently concentrated in Arkansas, Oklahoma, Pennsylvania and Texas. Southwestern's marketing and gas gathering business ("Midstream Services") is concentrated in the core areas of its E&P operations.

The accompanying unaudited condensed consolidated financial statements were prepared using accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and in accordance with the rules and regulations of the SEC. Certain information relating to the Company's organization and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been appropriately condensed or omitted in this Quarterly Report on Form 10-Q. The Company believes that the disclosures made are adequate to make the information presented not misleading.

The unaudited condensed consolidated financial statements contained in this report include all normal and recurring material adjustments that, in the opinion of management, are necessary for a fair presentation of the financial position, results of operations and cash flows for the interim periods presented herein. It is recommended that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and the notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2008 ("2008 Annual Report on Form 10-K").

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 Company's 2008 Annual Report on Form 10-K.

On January 1, 2009, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 160, "Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No. 51" ("SFAS 160"). SFAS 160 establishes accounting and reporting standards for (1) ownership interests in subsidiaries held by others, (2) the amount of consolidated net income attributable to the controlling and noncontrolling interests, (3) changes in the controlling ownership interest, (4) the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated and (5) disclosures that clearly identify and distinguish between the interests of the controlling and noncontrolling owners. The adoption of SFAS 160 resulted in changes to our presentation for noncontrolling interests and did not have a material impact on the Company's results of operations and financial condition.

The Company adopted SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133" ("SFAS 161"), on January 1, 2009. SFAS 161 requires enhanced disclosure about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended ("SFAS 133") and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The adoption of SFAS 161 did not have a material impact on the Company's results of operations and financial condition.

On January 1, 2009, the Company adopted Financial Accounting Standards Board ("FASB") Staff Position FAS 157-2, "Effective Date of FASB Statement No. 157" ("FSP FAS 157-2"). FSP FAS 157-2 delayed the effective date of SFAS No. 157, "Fair Value Measurements," 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). The adoption of FSP FAS 157-2 did not have a material impact on the Company's results of operations and financial condition.

Certain reclassifications have been made to the prior year's financial statements to conform to the 2009 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, less accumulated amortization and related deferred income taxes, 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 a periodic report may be utilized to calculate the ceiling value of reserves.

At March 31, 2009, the ceiling value of the Company's reserves was calculated based upon quoted market prices of $3.63 per MMBtu for Henry Hub natural gas and $46.00 per barrel for West Texas Intermediate oil, adjusted for market differentials. Using these prices, the net capitalized costs of our gas and oil properties exceeded the ceiling by approximately $558.3 million (net of tax) at March 31, 2009 and resulted in a non-cash ceiling test impairment. Cash flow hedges of gas production in place at March 31, 2009 increased the calculated ceiling value by approximately $450.6 million (net of tax). Decreases in market prices from March 31, 2009 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, 2009 and 2008, respectively.

	For the three months ended March 31, 2009	For the three months ended March 31, 2008
Net income (loss) attributable to Southwestern Energy (in thousands)	$ (432,830)	$ 109,029
Number of common shares:		
Weighted average outstanding	342,570,995	341,064,247
Issued upon assumed exercise of outstanding stock options	—	6,797,795
Effect of issuance of nonvested restricted common stock	—	334,465
Weighted average and potential dilutive outstanding(1)	342,570,995	348,196,507
Earnings per share:		
Net income (loss) attributable to Southwestern Energy stockholders - basic	$ (1.26)	$ 0.32
Net income (loss) attributable to Southwestern Energy stockholders - diluted	$ (1.26)	$ 0.31

(1) Due to the net loss for the three months ended March 31, 2009, options for 6,475,824 shares and 306,614 shares of restricted stock were antidilutive and excluded from the calculation. Options for 396,840 shares and 1,613 shares of restricted stock were excluded from the calculation for the three months ended March 31, 2008 because they would have had an antidilutive effect.

(4) DIVESTITURES

In November 2007, the Company entered into an agreement to sell all of the capital stock of its wholly-owned subsidiary, Arkansas Western Gas Company ("AWG"), for $224 million plus working capital. On July 1, 2008, the transaction was closed and the Company received $223.5 million (net of expenses related to the sale). In order to receive regulatory approval for the sale and certain related transactions, the Company paid $9.8 million to AWG for the benefit of its customers. The operating results and cash flows from AWG for the three months ended March 31, 2008 are included in the unaudited condensed consolidated statements of operations and statements of cash flows for the three months ended March 31, 2008. As a result of completion of the sale of AWG, the Company is no longer engaged in any natural gas distribution operations.

In the second quarter of 2008, the Company sold certain natural gas and oil leases, wells and gathering equipment in its Fayetteville Shale play for $518.3 million. Additionally, in the second and third quarters of 2008 the Company sold various natural gas and oil properties in the Gulf Coast and Permian Basin for approximately $240 million in the aggregate. All proceeds from the sales of natural gas and oil properties were credited to the full cost pool. The operating results and cash flows from the divested properties for the three months ended March 31, 2008 are included in the unaudited condensed consolidated statements of operations and statements of cash flows for the three months ended March 31, 2008.

(5) DEBT

The components of debt as of March 31, 2009 and December 31, 2008 consisted of the following:

	March 31, 2009	December 31, 2008
	(in thousands)	
Short-term debt:		
7.625% Senior Notes due 2027, putable at the holders' option in 2009	$ 60,000	$ 60,000
7.15% Senior Notes due 2018	1,200	1,200
Total short-term debt	61,200	61,200
Long-term debt:		
7.5% Senior Notes due 2018	600,000	600,000
7.21% Senior Notes due 2017	40,000	40,000
7.15% Senior Notes due 2018	34,200	34,200
Total long-term debt	674,200	674,200
Total debt	$ 735,400	$ 735,400

The Company has an unsecured revolving credit facility which expires in February 2012 ("Credit Facility"). The Credit Facility has a borrowing capacity of $1.0 billion which may be increased to $1.25 billion at any time upon the Company's agreement with its existing or additional lenders. As of March 31, 2009, the Company had no borrowings outstanding under the Credit Facility.

The Credit Facility is currently guaranteed by the Company's 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. In addition to the subsidiary guarantees, the Credit Facility restricts the ability of the Company's subsidiaries to incur debt and contains covenants which impose certain restrictions on the Company. Under the terms of the Credit Facility, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") to interest expense of 3.5 or above. At March 31, 2009 the Company's capital structure consisted of 25% debt and 75% equity and the Company is in compliance with the covenants of its debt agreements.

The Company's 7.625% Senior Notes due 2027 are putable by the note holders on May 1, 2009, and as a result, the $60 million principal balance of these notes has been reclassified to short-term debt. Subsequent to March 31, 2009, substantially all of the 7.625% Senior Notes were put to the Company by the holders and consequently the Company will pay approximately $62.1 million in principal and accrued interest on May 1, 2009.

(6) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company is providing unaudited condensed consolidating financial information for SEECO, SEPCO and SES, its subsidiaries that are guarantors of the Company's registered public debt, and for its other subsidiaries that are not guarantors of such debt. These wholly owned subsidiary guarantors have jointly and severally, fully and unconditionally guaranteed the Company's 7.625% Senior Notes and 7.21% Senior Notes. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are effectively subordinated to any future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; and (iv) are structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors.

The Company has not presented separate financial and narrative information for each of the subsidiary guarantors because it believes that such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the guarantees. The following unaudited condensed consolidating financial information summarizes the results of operations, financial position and cash flows for the Company's guarantor and non-guarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Three months ended March 31, 2009:					
Operating revenues	$ —	$ 524,829	$ 43,053	$ (27,065)	$ 540,817
Operating costs and expenses:					
Gas purchases	—	149,246	—	(66)	149,180
Operating expenses	—	40,880	13,179	(26,887)	27,172
General and administrative expenses	—	20,820	3,001	(112)	23,709
Depreciation, depletion and amortization	—	119,786	4,442	—	124,228
Impairment of natural gas and oil properties	—	907,812	—	—	907,812
Taxes, other than income taxes	—	8,450	758	—	9,208
Total operating costs and expenses	—	1,246,994	21,380	(27,065)	1,241,309
Operating income (loss)	—	(722,165)	21,673	—	(700,492)
Other income (loss)	—	361	4	—	365
Equity in earnings of subsidiaries	(432,830)	—	—	432,830	—
Interest expense	—	2,949	735	—	3,684
Income (loss) before income taxes	(432,830)	(724,753)	20,942	432,830	(703,811)
Provision (benefit) for income taxes	—	(279,020)	8,061	—	(270,959)
Net income (loss)	(432,830)	(445,733)	12,881	432,830	(432,852)
Less: Net income (loss) attributable to noncontrolling interest	—	(22)	—	—	(22)
Net income (loss) attributable to Southwestern Energy	$ (432,830)	$ (445,711)	$ 12,881	$ 432,830	$ (432,830)
Three months ended March 31, 2008:					
Operating revenues	$ —	$ 450,611	$ 106,720	$ (33,225)	$ 524,106
Operating costs and expenses:					
Gas purchases	—	146,873	58,656	(21,182)	184,347
Operating expenses	—	21,902	13,995	(11,901)	23,996
General and administrative expenses	—	17,699	6,183	(142)	23,740
Depreciation, depletion and amortization	—	93,007	4,090	—	97,097
Taxes, other than income taxes	—	5,934	1,482	—	7,416
Total operating costs and expenses	—	285,415	84,406	(33,225)	336,596
Operating income	—	165,196	22,314	—	187,510
Other income (loss)	—	113	(106)	—	7
Equity in earnings of subsidiaries	109,029	—	—	(109,029)	—
Interest expense	—	8,592	2,937	—	11,529
Income before income taxes	109,029	156,717	19,271	(109,029)	175,988
Provision for income taxes	—	59,501	7,323	—	66,824
Net income	109,029	97,216	11,948	(109,029)	109,164
Less: Net income attributable to noncontrolling interest	—	135	—	—	135
Net income attributable to Southwestern Energy	$ 109,029	$ 97,081	$ 11,948	$ (109,029)	$ 109,029

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
March 31, 2009:					
ASSETS					
Cash and cash equivalents	$ 82,139	$ —	$ 183	$ —	$ 82,322
Accounts receivable	428	206,172	3,234	—	209,834
Inventories	—	34,532	813	—	35,345
Other	29,869	495,337	485	—	525,691
Total current assets	112,436	736,041	4,715	—	853,192
Intercompany receivables	1,363,759	(971,174)	(382,908)	(9,677)	—
Investments	—	10,309	(10,308)	(1)	—
Property and equipment	58,925	5,296,555	485,204	—	5,840,684
Accumulated depreciation, depletion and amortization	(32,501)	(2,574,741)	(41,088)	—	(2,648,330)
Net property and equipment	26,424	2,721,814	444,116	—	3,192,354
Investments in subsidiaries (equity method)	1,473,751	—	—	(1,473,751)	—
Other assets	13,470	113,579	55,981	—	183,030
Total assets	$ 2,989,840	$ 2,610,569	$ 111,596	$ (1,483,429)	$ 4,228,576
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 218,560	$ 317,998	$ 23,511	$ (9,678)	$ 550,391
Other current liabilities	1,843	287,325	4,476	—	293,644
Total current liabilities	220,403	605,323	27,987	(9,678)	844,035
Long-term debt	674,200	—	—	—	674,200
Other liabilities	24,545	16,788	4,799	—	46,132
Commitments and contingencies					
Deferred income taxes	(103,632)	570,453	23,064	—	489,885
Total liabilities	815,516	1,192,564	55,850	(9,678)	2,054,252
Total equity	2,174,324	1,418,005	55,746	(1,473,751)	2,174,324
Total liabilities and equity	$ 2,989,840	$ 2,610,569	$ 111,596	$ (1,483,429)	$ 4,228,576

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2008:					
ASSETS					
Cash and cash equivalents	$ 195,969	$ —	$ 308	$ —	$ 196,277
Accounts receivable	404	250,687	3,466	—	254,557
Inventories	—	49,579	798	—	50,377
Other	9,837	377,455	762	—	388,054
Total current assets	206,210	677,721	5,334	—	889,265
Intercompany receivables	1,252,573	(896,577)	(347,293)	(8,703)	—
Investments	—	10,309	(10,308)	(1)	—
Property and equipment	57,438	4,844,970	426,506	—	5,328,914
Accumulated depreciation, depletion and amortization	(30,679)	(1,548,927)	(35,701)	—	(1,615,307)
Net property and equipment	26,759	3,296,043	390,805	—	3,713,607
Investments in subsidiaries (equity method)	1,822,057	—	—	(1,822,057)	—
Other assets	13,983	99,547	43,756	—	157,286
Total assets	$ 3,321,582	$ 3,187,043	$ 82,294	$ (1,830,761)	$ 4,760,158
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 241,227	$ 330,270	$ 15,360	$ (8,704)	$ 578,153
Other current liabilities	1,810	210,087	2,811	—	214,708
Total current liabilities	243,037	540,357	18,171	(8,704)	792,861
Long-term debt	674,200	—	—	—	674,200
Other liabilities	25,723	22,686	5,018	—	53,427
Commitments and contingencies					
Deferred income taxes	(139,341)	845,593	15,455	—	721,707
Total liabilities	803,619	1,408,636	38,644	(8,704)	2,242,195
Total equity	2,517,963	1,778,407	43,650	(1,822,057)	2,517,963
Total liabilities and equity	$ 3,321,582	$ 3,187,043	$ 82,294	$ (1,830,761)	$ 4,760,158

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Three months ended March 31, 2009:					
Net cash provided by operating activities	$ 31,055	$ 361,094	$ 15,146	$ —	$ 407,295
Investing activities:					
Capital investments	(2,946)	(426,019)	(51,518)	—	(480,483)
Other	1,822	(7,139)	947	—	(4,370)
Net cash used in investing activities	(1,124)	(433,158)	(50,571)	—	(484,853)
Financing activities:					
Intercompany activities	(107,364)	72,064	35,300	—	—
Other items	(36,397)	—	—	—	(36,397)
Net cash provided by (used in) financing activities	(143,761)	72,064	35,300	—	(36,397)
Decrease in cash and cash equivalents	(113,830)	—	(125)	—	(113,955)
Cash and cash equivalents at beginning of year	195,969	—	308	—	196,277
Cash and cash equivalents at end of period	$ 82,139	$ —	$ 183	$ —	$ 82,322
Three months ended March 31, 2008:					
Net cash provided by operating activities	$ 6,813	$ 265,420	$ 24,854	$ —	$ 297,087
Investing activities:					
Capital investments	(1,096)	(357,600)	(32,333)	—	(391,029)
Other	1,523	(600)	(461)	—	462
Net cash provided by (used in) investing activities	427	(358,200)	(32,794)	—	(390,567)
Financing activities:					
Intercompany activities	(101,380)	92,780	8,600	—	—
Payments on revolving long-term debt	(927,400)	—	—	—	(927,400)
Borrowings under revolving long-term debt	426,400	—	—	—	426,400
Proceeds from issuance of long-term debt	600,000	—	—	—	600,000
Other items	(5,146)	—	—	—	(5,146)
Net cash provided by (used in) financing activities	(7,526)	92,780	8,600	—	93,854
Increase (decrease) in cash and cash equivalents	(286)	—	660	—	374
Cash and cash equivalents at beginning of year	433	—	1,399 (1)	—	1,832
Cash and cash equivalents at end of period	$ 147	$ —	$ 2,059 (1)	$ —	$ 2,206

(1) Cash and cash equivalents at the beginning of the year for 2008 and at March 31, 2008 include $1.1 million and $1.7 million, respectively, classified as “held for sale.” See Note 4 for additional information.

(7) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to commodity price risk which impacts the predictability of its cash flows related to the sale of natural gas and oil. The primary risk managed by the Company's use of certain derivative financial instruments is commodity price risk. These derivative financial instruments allow the Company to limit its exposure to a portion of its projected natural gas sales. At March 31, 2009 and December 31, 2008, the Company's derivative financial instruments consisted of price swaps, costless collars and basis swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty.
Floating price swaps	The Company receives a floating market price from the counterparty and pays a fixed price.
Costless-collars	Contain a fixed floor price (put) and a fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.
Basis swaps	Matched and unmatched arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

SFAS 133 requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Under SFAS 133, certain criteria must be satisfied in order for derivative financial instruments to be classified and accounted for as either a cash flow or a fair value hedge. Accounting for qualifying hedges requires a derivative's gains and losses to be recorded as a component of other comprehensive income. Gains and losses on derivatives that are not elected for hedge accounting treatment or that do not meet the requirements of SFAS 133 are recorded in earnings.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy entities at the time the transactions are entered into and the Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the recent events in the financial markets demonstrate there can be no assurance that a counterparty financial institution will be able to meet its obligations to the Company.

None of the Company's derivative instruments contain credit-risk-related contingent features other than one derivative instrument which expires in December 2009. The credit-risk-related contingent feature is triggered when a net liability owed to the counterparty with the credit-risk-related contingent feature exceeds a threshold amount. The cash collateral amount that may be required to be remitted to the counterparty upon the trigger of the credit-risk-related contingent feature is equal to the net liability owed to the counterparty less the threshold amount. The derivative instrument containing the credit-risk-related contingent feature is in a net asset position as of March 31, 2009 and no amounts have been remitted as collateral to the counterparty. The Company has not incurred any credit-related losses associated with its derivative activities and believes that its counterparties will continue to be able to meet their obligations under these transactions.

The balance sheet classification of the assets and liabilities related to derivative financial instruments are summarized below at March 31, 2009 and December 31, 2008:

	Derivative Assets			
	2009		2008	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments				
Fixed and floating price swaps	Hedging asset	$ 284,448	Hedging asset	$ 174,985
Costless-collars	Hedging asset	170,096	Hedging asset	165,671
Fixed and floating price swaps	Other Assets	81,736	Other Assets	66,349
Costless-collars	Other Assets	24,863	Other Assets	26,202
Total derivatives designated as hedging instruments		$ 561,143		$ 433,207
Derivatives not designated as hedging instruments				
Basis swaps	Hedging asset	$ 2,067	Hedging asset	$ 2,664
Basis swaps	Other Assets	1,316	Other Assets	1,844
Total derivatives not designated as hedging instruments		$ 3,383		$ 4,508
Total derivative assets		$ 564,526		$ 437,715

	Derivative Liabilities			
	2009		2008	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments				
Fixed and floating price swaps	Hedging liability	$ 1,165	Hedging liability	$ 2,679
Costless-collars	Hedging liability	1,404	Hedging liability	5,670
Fixed and floating price swaps	Long-term hedging liability	632	Long-term hedging liability	557
Costless-collars	Long-term hedging liability	1,601	Long-term hedging liability	5,142
Total derivatives designated as hedging instruments		$ 4,802		$ 14,048
Derivatives not designated as hedging instruments				
Basis swaps	Hedging liability	$ 1,679	Hedging liability	$ 2,550
Basis swaps	Long-term hedging liability	621	Long-term hedging liability	235
Total derivatives not designated as hedging instruments		$ 2,300		$ 2,785
Total derivative liabilities		$ 7,102		$ 16,833

Cash Flow Hedges

The reporting of gains and losses on cash flow derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gains and losses on the derivative hedging instrument are recorded in other comprehensive income until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from the derivative hedging instrument is recognized in earnings immediately.

As of March 31, 2009 and 2008, the Company had cash flow hedges on the following volumes of gas production:

	2009	2008
Natural Gas (Bcf):		
Fixed price swaps:		
2008	—	64.5
2009	63.0	76.0
2010	36.0	28.0
Costless-collars:		
2008	—	30.0
2009	36.0	47.0
2010	14.0	14.0
Matched-basis swaps:		
2008	—	4.5

At March 31, 2009, the Company recorded a net gain to other comprehensive income of $343.6 million related to its hedging activities, net of a deferred income tax liability of $212.4 million. The amount recorded in other comprehensive income will be relieved over time and taken to the statement of operations as the physical transactions being hedged occur. Assuming the market prices of gas futures as of March 31, 2009 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $279.3 million from accumulated other comprehensive income to earnings during the next 12 months. Gains or losses from derivative instruments designated as cash flow hedges are reflected as adjustments to gas sales in the unaudited condensed consolidated statements of operations. Gas sales included a realized gain from settled contracts of $141.5 million in the first quarter of 2009, compared to a realized gain of $19.0 million in the first quarter of 2008 related to cash flow hedges. Volatility in earnings and other comprehensive income may occur in the future as a result of the application of SFAS 133.

The following tables summarize the effect of all cash flow hedges on the unaudited condensed consolidated statements of operations for the three months ended March 31, 2009 and 2008:

Derivative Instrument	Gain(Loss) Recognized in Other Comprehensive Income (Effective Portion) 2009	2008
	(in thousands)	
Fixed price swaps	$ 224,992	$ (132,267)
Costless-collars	$ 118,598	$ (36,208)
Matched-basis swaps	$ —	$ 980

Derivative Instrument	Classification of Gain(Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain(Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion) 2009	2008
		(in thousands)	
Fixed price swaps	Gas Sales	$ 53,414	$ 7,046
Costless-collars	Gas Sales	$ 88,043	$ 12,786
Matched-basis swaps	Gas Sales	$ —	$ (812)

Derivative Instrument	Classification of Gain(Loss) Recognized in Earnings (Ineffective Portion)	Gain(Loss) Recognized in Earnings (Ineffective Portion) 2009	2008
		(in thousands)	
Fixed price swaps	Gas Sales	$ 365	$ (2,996)
Costless-collars	Gas Sales	$ 48	$ (2,094)
Matched-basis swaps	Gas Sales	$ —	$ —

Fair Value Hedges

For fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item are recognized in current earnings. As of March 31, 2009 and 2008, the Company had fair value hedges on the following volumes of gas production:

	2009	2008
Natural Gas (Bcf):		
Floating price swaps:		
2008	—	2.3
2009	0.2	0.5
2010	0.2	—

The following table summarizes the effect of all fair value hedges on the unaudited condensed consolidated statements of operations for the three months ended March 31, 2009 and 2008:

Derivative Instrument	Income Statement Classification of Gain(Loss)	Unrealized Gain(Loss) Recognized in Earnings 2009	2008	Realized Gain(Loss) Recognized in Earnings 2009	2008
			(in thousands)		
Floating price swaps	Gas Sales	$ (41)	$ 753	$ 2,071	$ 730

Other Derivative Contracts

Although the Company's basis swaps meet the objective of managing commodity price exposure, these trades are typically not entered into concurrent with the Company's derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting under SFAS 133. Basis swap derivative instruments that do not qualify as cash flow hedges are recorded on the balance sheet at their fair values under hedging assets, other assets and hedging liabilities, and all realized and unrealized gains and losses related to these contracts are recognized immediately in the unaudited condensed consolidated statements of operations as a component of gas sales. Gas sales included an unrealized loss of $0.6 million for the three months ended March 31, 2009, compared to an unrealized gain of $5.4 million for the three months ended March 31, 2008 for non-qualifying basis swaps.

As of March 31, 2009 and 2008, the Company had basis swaps on the following volumes of gas production that did not qualify for hedge treatment:

	2009	2008
Natural Gas (Bcf):		
Basis Swaps:		
2008	—	54.3
2009	39.7	3.6
2010	39.3	—
2011	9.0	—

The following table summarizes the effect of basis swaps that did not qualify for hedge accounting on the unaudited condensed consolidated statements of operations for the three months ended March 31, 2009 and 2008:

Derivative Instrument	Income Statement Classification of Gain(Loss)	Unrealized Gain(Loss) Recognized in Earnings 2009	Unrealized Gain(Loss) Recognized in Earnings 2008	Realized Gain(Loss) Recognized in Earnings 2009	Realized Gain(Loss) Recognized in Earnings 2008
		(in thousands)			
Basis swaps	Gas Sales	$ 1,082	$ 4,648	$ 2,863	$ (1,189)

(8) FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company partially adopted SFAS 157, "Fair Value Measurements" ("SFAS 157"), which defines fair value, provides a framework for measuring fair value under GAAP and expands the required disclosures about fair value measurements. The Company adopted SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS 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 SFAS 159 for any of its financial instruments that are not currently measured at fair value.

SFAS 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 valuations - Consist of quoted market information for the calculation of fair market value.

Level 3 valuations - Consist of internal estimates and have the lowest priority.

Pursuant to SFAS 157, the Company has classified its derivatives into these levels depending upon the data relied on to determine the fair values. The Company's fixed-price and floating-price swaps are estimated using internal discounted cash flow calculations using the NYMEX futures index and are designated as Level 2. The fair values of costless-collars and 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, 2009 (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	$ —	$ 366,184	$ 198,342	$ 564,526
Derivative liabilities	—	(1,796)	(5,306)	(7,102)
Total	$ —	$ 364,388	$ 193,036	$ 557,424

The table below presents reconciliations for assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three months ended March 31, 2009. 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, 2009.

Total Gains and Losses for the three months ended March 31, 2009 (Level 3 Only)

	Net Derivatives (in thousands)
Balance at January 1, 2009	$ 182,823
Total gains or losses (realized/unrealized):	
Included in earnings	91,902
Included in other comprehensive income (loss)	11,569
Purchases, issuances, and settlements	(93,258)
Transfers into/out of Level 3	—
Balance at March 31, 2009	$ 193,036
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of March 31, 2009	$ (1,356)

(9) SEGMENT INFORMATION

The Company's reportable business segments 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 gathering fees associated with the transportation of natural gas to market and through the marketing of both Company and third-party produced gas volumes. 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 arose from the transportation and retail sale of natural gas by AWG. As a result of the disposition of AWG on July 1, 2008, the Company no longer has 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 2008 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. 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, 2009:					
Revenues from external customers	$ 369,333	$ 171,364	$ —	$ 120	$ 540,817
Intersegment revenues	8,752	222,110	—	112	230,974
Operating income (loss)	(727,893)[(1)]	27,362	—	39	(700,492)
Interest and other income[(2)]	363	—	—	2	365
Depreciation, depletion and amortization expense	120,131	3,926	—	171	124,228
Impairment of natural gas and oil properties	907,812	—	—	—	907,812
Interest expense[(2)]	3,243	441	—	—	3,684
Provision (benefit) for income taxes[(2)]	(281,339)	10,365	—	15	(270,959)
Assets	3,506,323	525,331	—	196,922 [(3)]	4,228,576
Capital investments[(4)]	450,403	50,921	—	1,868	503,192

	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
Interest and other income (loss)(2)	114	—	(107)	—	7
Depreciation, depletion and amortization expense	93,306	2,037	1,718	36	97,097
Interest expense(2)	8,770	1,551	1,208	—	11,529
Provision for income taxes(2)	59,629	3,272	3,904	19	66,824
Assets	3,351,181	354,207	194,283	75,091 (3)	3,974,762
Capital investments(4)	376,514	31,445	991	908	409,858

(1) The operating loss for the E&P segment for the three months ended March 31, 2009 includes a $907.8 million non-cash ceiling test impairment of our natural gas and oil properties resulting from the significant decline in natural gas prices since December 31, 2008.
(2) Interest income, interest expense and the provision (benefit) for income taxes by segment are allocated as they are incurred at the corporate level.
(3) Other assets represent corporate assets not allocated to segments and assets, including investments in cash equivalents, for non-reportable segments.
(4) Capital investments include increases of $23.6 million and $16.8 million for the three months ended March 31, 2009 and 2008, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $195.3 million and $239.1 million for the three months ended March 31, 2009 and 2008, 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 were priced in accordance with terms of existing contracts and current market conditions. Corporate assets include cash and cash equivalents, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. All of the Company's operations are located within the United States.

(10) INTEREST AND INCOME TAXES

Interest payments of $23.4 million and $5.7 million were made for the three months ended March 31, 2009 and 2008, respectively. There were no tax payments made in these periods.

The Company had an increase of approximately $50 million in unrecognized tax benefits as of March 31, 2009 related to alternative minimum taxes associated with uncertain tax positions. If these unrecognized tax benefits are disallowed, any payments can be utilized against future regular tax liabilities. The Company paid $21.0 million in 2008 related to these unrecognized tax benefits. We do not expect to be subject to current income taxes in 2009.

(11) CONTINGENCIES AND COMMITMENTS

Operating Commitments and Contingencies

On April 1, 2009, Texas Gas Transmission LLC, a subsidiary of Boardwalk Pipeline Partners, L.P. or Texas Gas, placed in service the entire Fayetteville-Greenville Expansion project, which included a section of 18-inch pipeline under the Little Red River in Arkansas in the Fayetteville Lateral that will be replaced with a 36-inch pipeline once a new horizontal directional drill is completed under the river. The initial peak-day transmission capacity of the Fayetteville Lateral is approximately 0.8 Bcf per day. Texas Gas has indicated that it expects the 36-inch pipeline installation to be completed in the second quarter of 2009, with an initial peak-day transmission capacity of the Fayetteville Lateral of approximately 0.8 Bcf per day that would increase to approximately 1.3 Bcf per day once Texas Gas adds compression facilities to Fayetteville Lateral and receives from the Pipelines and Hazardous Materials Safety Administration ("PHMSA") authority to operate under a special permit allowing higher operating pressures. The Fayetteville Shale Compression Project has been filed with the Federal Energy Regulatory Commission ("FERC") to support the Fayetteville-Greenville Expansion Project, pursuant to which Texas Gas is proposing to construct, own and operate two new compressor stations to increase transmission capacity. Texas Gas expects the additional capacity to be in service in the first half of 2010, subject to FERC approval.

Under the Company's long-term firm transportation agreements with Texas Gas, the Company has subscribed for capacity that increases over time subject to the installation of the 36-inch line, receipt of the PHMSA approval and/or the installation of the compression facilities. Under its long-term firm transportation agreements for the Fayetteville Lateral, the Company currently has 350,000 MMBtu/d of capacity, which will increase to 400,000 MMBtu/d on November 1, 2009, 450,000 MMBtu/d on November 1, 2010 and 500,000 MMBtu/d on November 1, 2011; provided, however, that on the first day of the month after Texas Gas has received the PHMSA approval and authority from the FERC to operate the Fayetteville Lateral at a capacity of 950,000 MMBtu/d, the Company's subscribed capacity will immediately increase to 500,000 MMBtu/d. Once the 36-inch line underneath the Little Red River is completed, the Company will have an additional 55,000 MMBtu/d of capacity on the Fayetteville Lateral, which will increase to 100,000 MMBtu/d (or 150,000 MMBtu/d if the PHMSA and FERC approvals have been obtained) beginning April 1, 2010, 200,000 MMBtu/d (or 250,000 MMBtu/d if the PHMSA and FERC approvals have been obtained) beginning April 1, 2011, and 300,000 MMBtu/d beginning April 1, 2012; provided, however, that on the first day of the month after Texas Gas has received the PHMSA and FERC approvals and the compression facilities have been installed, the additional subscribed capacity will immediately increase to 300,000 MMBtu/d. Under its long-term firm transportation agreements for the Greenville Lateral, the Company currently has 280,000 MMBtu/d of capacity, which will increase to 320,000 MMBtu/d on November 1, 2009, 360,000 MMBtu/d on November 1, 2010 and 400,000 MMBtu/d on November 1, 2011; provided, however, that on the first day of the month after Texas Gas has received the PHMSA and FERC approvals, the Company's subscribed capacity will immediately increase to 400,000 MMBtu/d. The Company will have additional capacity on the Greenville Lateral of 80,000 MMBtu/d beginning April 1, 2010, 160,000 MMBtu/d beginning April 1, 2011, and 240,000 MMBtu/d beginning April 1, 2012; provided, however, that on the later of April 1, 2010, or the first day of the month after Texas Gas has completed installation of compression facilities at Isola, Mississippi, the additional subscribed capacity will immediately increase to 240,000 MMBtu/d.

In addition to its long-term firm transportation agreements, the Company has short-term transportation agreements on the Fayetteville Lateral providing 147,500 MMBtu/d of capacity for April and May of 2009, 50,000 MMBtu/d of capacity in June 2009, 125,000 MMBtu/d of capacity from April 1, 2010 through December 31, 2010 and 25,000 MMBtu/d of capacity from January 1, 2011 to December 31, 2011.

In April 2009, Texas Gas announced that there would be temporary reductions on the Fayetteville Lateral due to various activities, including maintenance and pipeline inspection. The exact completion date for these activities is unknown, but is expected to occur by the end of the third quarter. As a result, transportation on the Fayetteville Lateral as of April 24, 2009 was approximately 700,000 MMBtu/d, and the Company's capacity was approximately 500,000 MMBtu/d to Bald Knob, Arkansas, including approximately 365,000 MMBtu/d to Lula, Mississippi. The Company expects that the remainder of its Fayetteville Shale production will continue to be transported on other pipelines to Midwest markets until these issues are resolved.

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 financial position or reported results of operations of the Company.

(12) 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 12 of the Notes to Consolidated Financial Statements included in Item 8 of the 2008 Annual Report on Form 10-K.

For the three months ended March 31, 2009 and 2008, the Company recorded compensation cost of $1.1 million and $0.8 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.5 million and $0.2 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. The Company also recorded a deferred tax benefit of $0.2 million related to stock options for the three months ended March 31, 2009, compared to a deferred tax benefit of $0.2 million for the same period in 2008. As of March 31, 2009, a total of $10.7 million of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods.

For the three months ended March 31, 2009 and 2008, the Company recorded compensation cost of $1.1 million and $0.9 million, respectively, in general and administrative expense related to restricted stock grants. Additional amounts of $1.0 million and $0.7 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, 2009, there was $18.1 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 2009 and provide information for options outstanding at March 31, 2009.

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2008	7,396,537	$ 7.44
Granted	28,125	29.36
Exercised	(2,000)	1.57
Forfeited or expired	—	—
Outstanding at March 31, 2009	7,422,662	$ 7.52
Exercisable at March 31, 2009	6,444,678	$ 4.25

For the first three months of 2009, there were 28,125 options granted, compared to 14,000 options granted for the first three months of 2008. The total intrinsic value of options exercised for the first three months of 2009 and 2008 was $0.1 million and $9.4 million, respectively.

	Options Outstanding				Options Exercisable			
Range of Exercise Prices	Options Outstanding at March 31, 2009	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at March 31, 2009	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)
$0.75 - $1.00	2,042,464	$ 0.92	1.6		2,042,464	$ 0.92	1.6	
$1.01 - $2.50	1,811,238	1.39	3.1		1,811,238	1.39	3.1	
$2.51 - $16.75	1,826,932	4.09	3.8		1,826,932	4.09	3.8	
$16.76 - $30.00	1,158,308	21.95	4.5		764,044	20.34	4.1	
$30.01 - $44.34	583,720	31.79	6.7		—	—	—	
	7,422,662	$ 7.52	3.4	$ 164,549	6,444,678	$ 4.25	2.9	$ 163,953

The following table summarizes restricted stock activity for the first three months of 2009.

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2008	843,430	$ 27.66
Granted	8,835	30.41
Vested	(13,325)	21.45
Forfeited	(2,284)	23.82
Unvested shares at March 31, 2009	836,656	$ 27.79

(13) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" ("SFAS 158"). 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 months ended March 31, 2009 and 2008:

	Pension Benefits For the three months ended March 31,	
	2009	2008
	(in thousands)	
Service cost	$ 1,287	$ 1,408
Interest cost	718	1,210
Expected return on plan assets	(702)	(1,255)
Amortization of prior service cost	83	122
Amortization of net loss	212	174
Net periodic benefit cost	$ 1,598	$ 1,659

	Other Postretirement Benefits For the three months ended March 31,	
	2009	2008
	(in thousands)	
Service cost	$ 174	$ 165
Interest cost	34	77
Expected return on plan assets	—	(24)
Amortization of transition obligation	16	22
Amortization of prior service cost	3	3
Amortization of net loss	2	17
Net periodic benefit cost	$ 229	$ 260

The Company currently expects to contribute $8.0 million to the pension plans and $0.1 million to the postretirement benefit plans in 2009. As of March 31, 2009, $2.0 million has been contributed to the pension plans and there have been no contributions to the postretirement benefit plans.

The Company maintains a non-qualified defined contribution supplemental retirement savings plan ("Non-Qualified Plan") for certain key employees who may elect to defer and contribute a portion of their compensation, as permitted by the plan. Shares of the Company's common stock purchased under the terms of the Non-Qualified Plan are presented as treasury stock. As of March 31, 2009, treasury stock held by the Company under the terms of the Non-Qualified Plan totaled 202,624 shares, compared to 225,050 shares at December 31, 2008.

(14) INVENTORY

The Company has one facility containing gas in underground storage. The current portion of the gas is classified in inventory and carried at the lower of cost or market. The non-current portion of the gas is classified in property and equipment and carried at cost. The carrying value of the non-current gas is evaluated for recoverability when either events or changes in circumstances indicate that it may not be recoverable. Withdrawals of current gas in underground storage are accounted for by utilizing a weighted average cost method whereby gas withdrawn from storage is relieved at the weighted average cost of current gas remaining in the facility.

Due to lower commodity prices at March 31, 2009, the Company recorded a non-cash impairment charge of $4.3 million for the three months ended March 31, 2009 to reduce the current portion of the Company's natural gas inventory to the lower of cost or market. This charge is reflected as a reduction to other operating revenues in the unaudited condensed consolidated statements of operations for the three months ended March 31, 2009. The Company's current portion of natural gas inventory at March 31, 2009 is $9.5 million, after recognition of the non-cash impairment charge, compared to $24.1 million at December 31, 2008. Also included in the inventory recorded in current assets at March 31, 2009 and December 31, 2008, is $25.9 million and $26.3 million, respectively, of tubulars and other equipment used in the Company's E&P segment.

Other assets includes $49.7 million at March 31, 2009, and $43.8 million at December 31, 2008, for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems for the Fayetteville Shale play.

Tubulars and other equipment used by the Company's segments are carried at the lower of cost or market and are accounted for by utilizing a moving weighted average cost method that is applied within specific classes of inventory items. Purchases of inventory are recorded at cost and inventory is relieved at the weighted average cost of items remaining within a specified inventory class.

(15) SUBSEQUENT EVENTS

On April 8, 2009, the Company's Board of Directors approved and the Company entered into, a Second Amended and Restated Rights Agreement ("Rights Agreement"), dated as of April 9, 2009, between the Company and Computershare Trust Company, N.A., which amended, restated, superseded and replaced the Amended and Restated Rights Agreement dated as of April 12, 1999, as amended. The Rights Agreement extends the term of the agreement until April 8, 2019 and amends each Right (which initially represented the right to purchase one share of the Common Stock) to represent the right to purchase, when exercisable, a unit consisting of one one-thousandth of a share ("Unit") of Series A Junior Participating Preferred Stock, par value $0.01 per share ("Series A Preferred Stock") at a purchase price of $150.00 per Unit ("Purchase Price"), subject to adjustment.

In connection with the Rights Agreement, the Board of Directors approved the Certificate of Designation, Preferences and Rights ("Certificate of Designation") establishing the Series A Preferred Stock, which was filed with the Secretary of State of the State of Delaware on April 9, 2009, and reserved 1,000,000 shares for issuance under the Rights Agreement.

Pursuant to the Certificate of Designation, when issued, each share of the Series A Preferred Stock entitles the holder thereof to 1,000 votes, subject to adjustment, on all matters submitted to a vote of the stockholders of the Company. Except as otherwise set forth in the Certificate of Designation or provided by law, the holders of shares of the Series A Preferred Stock and the holders of shares of the Common Stock will vote together as one class on all matters submitted to a vote of stockholders of the Company.

(16) NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In April 2009, the FASB issued FSP FAS 107-1 and Accounting Principles Board ("APB") Opinion No. 28-1 (collectively, "FSP FAS 107-1"), "Interim Disclosures about Fair Value of Financial Instruments." FSP FAS 107-1 amends SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," to require an entity to provide disclosures about fair value of financial instruments in interim financial information. The FSP FAS 107-1 also amends APB Opinion No. 28, "Interim Financial Reporting," to require those disclosures about the fair value of financial instruments in summarized financial information at interim reporting periods. Under FSP FAS 107-1, the Company will be required to include disclosures about the fair value of its financial instruments whenever it issues financial information for interim reporting periods. In addition, the Company will be required to disclose in the body or in the accompanying notes of its summarized financial information for interim reporting periods and in its financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. FSP FAS 107-1 is effective for periods ending after June 15, 2009 and its adoption is expected to have no impact on the Company's results of operations and financial condition but will require additional disclosures about the fair value of financial instruments in its financial statements.

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 2008 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three month periods ended March 31, 2009 and 2008. For definitions of commonly used natural gas and oil terms used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2008 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 2008 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 unaudited condensed consolidated financial statements and the related notes included in this Form 10-Q.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily engaged in natural gas and crude oil exploration, development and production ("E&P") within the United States. We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses ("Midstream Services"). We have historically operated principally in three segments: E&P, Midstream Services and Natural Gas Distribution. On July 1, 2008, we closed the sale of our utility subsidiary, Arkansas Western Gas Company ("AWG") and, as a result, we no longer have any natural gas distribution operations. The operating results and cash flows from AWG for the three months ended March 31, 2008 are included in the unaudited condensed consolidated statements of operations and statements of cash flows and are not presented as "discontinued operations." We refer you to Note 4 to the unaudited condensed 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. 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 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 in turn determines the sale prices for our production. In addition, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices. We are subject to credit risk relating to the risk of loss as a result of non-performance by counterparties in our hedging activities. 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 closely monitored to limit our credit risk exposure. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Three Months Ended March 31, 2009, Compared with Three Months Ended March 31, 2008

Our natural gas and oil production increased to 63.9 Bcfe for the three months ended March 31, 2009, up 64% from the three months ended March 31, 2008. The 24.8 Bcfe increase in 2009 production was due to a 26.6 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program, partially offset by decreases in net production resulting from the sale of all of our producing properties in the Permian Basin and Gulf

Coast. The average price realized for our gas production, including the effects of hedges, decreased approximately 23% to $5.94 per Mcf for the three months ended March 31, 2009, as compared to the same period in 2008.

We reported a net loss of ($432.8) million for the three months ended March 31, 2009, or ($1.26) per share on a fully diluted basis, down from net income of $109.0 million, or $0.31 per diluted share, for the comparable period in 2008. The loss for the three months ended March 31, 2009 includes a $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties resulting from a significant decline in natural gas prices since December 31, 2008.

Our E&P segment reported an operating loss of ($727.9) million for the three months ended March 31, 2009, down $893.6 million from the comparable period of 2008, due to the $907.8 million non-cash ceiling test impairment of our natural gas and oil properties, decreased prices realized from the sale of our production and an increase in operating costs and expenses of $51.9 million, which were partially offset by an increase in revenues of $66.1 million from higher gas production volumes. Operating income for our Midstream Services segment was $27.4 million for the three months ended March 31, 2009, up from $10.2 million for the three months ended March 31, 2008, due to an increase of $22.8 million in gathering revenues and an increase of $4.0 million in the margin generated from our natural gas marketing activities, which were partially offset by a $9.6 million increase in operating costs and expenses, exclusive of gas purchased costs. Our Natural Gas Distribution segment had operating income of $11.6 million for the three months ended March 31, 2008.

We had capital investments of $503.2 million for the three months ended March 31, 2009, of which $450.4 million was invested in our E&P segment, compared to $409.9 million for the same period of 2008, of which $376.5 million was invested in our E&P segment.

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense, interest income, income tax expense, pension expense and stock-based compensation are discussed on a consolidated basis.

Exploration and Production

	For the three months ended March 31,	
	2009	2008
Revenues (in thousands)	$ 378,085	$ 312,017
Impairment of natural gas and oil properties (in thousands)	$ 907,812	$ —
Operating costs and expenses (in thousands)	$ 198,166	$ 146,307
Operating income (loss) (in thousands)	$ (727,893)	$ 165,710
Gas production (MMcf)	63,689	38,205
Oil production (MBbls)	34	142
Total production (MMcfe)	63,893	39,057
Average gas price per Mcf, including hedges	$ 5.94	$ 7.70
Average gas price per Mcf, excluding hedges	$ 3.81	$ 7.46
Average oil price per Bbl	$ 34.90	$ 96.55
Average unit costs per Mcfe:		
Lease operating expenses	$ 0.78	$ 0.77
General & administrative expenses	$ 0.31	$ 0.42
Taxes, other than income taxes	$ 0.13	$ 0.16
Full cost pool amortization	$ 1.82	$ 2.30

Revenues

Revenues for our E&P segment were up $66.1 million, or 21%, for the three months ended March 31, 2009, compared to the same period in 2008. Of the $66.1 million increase in revenues, increased production volumes contributed approximately $185.9 million to the increase and were partially offset by a $114.6 million decrease attributable to lower realized natural gas and oil prices, a $4.3 million decrease related to the non-cash impairment of our natural gas inventory and a $0.9 million decrease resulting from other changes in our revenue. We expect our production volumes to continue to increase due to the development of our Fayetteville Shale play in Arkansas. Natural gas and oil prices are difficult to predict and subject to wide price fluctuations. As of April 24, 2009, we had hedged 99.0 Bcf of our remaining 2009 gas production and 50.0 Bcf of 2010 gas production to limit our exposure to price fluctuations. We refer you to Note 7 to the unaudited condensed consolidated financial statements included in this Form 10-Q and to the discussion of "Commodity Prices" provided below for additional information.

Production

Natural gas and oil production for the three months ended March 31, 2009 was up approximately 64%, from the comparable period in 2008, to 63.9 Bcfe, due to a 26.6 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program, which was partially offset by a decrease of 1.3 Bcfe in net production resulting from the sale of all of our producing properties in the Permian Basin and Gulf Coast. Our total gas production was up approximately 67% to 63.7 Bcf for the three months ended March 31, 2009, which represented nearly 100% of our total equivalent production. Net production from the Fayetteville Shale was 50.2 Bcf for the three months ended March 31, 2009, compared to 23.6 Bcf for the same period in 2008.

In the second quarter of 2008, we completed the sale of 55,631 net acres, or approximately 6% of our December 31, 2007 total net acres in the Fayetteville Shale play, for $518.3 million. Production from the acreage sold was approximately 10.5 MMcf per day at the time of the sale. Additionally, we sold our Gulf Coast and Permian Basin properties in the second and third quarters of 2008.

We increased our gas and oil production guidance for the second quarter of 2009 to 70.0 to 71.0 Bcfe, up from 67.0 to 68.0 Bcfe. Our guidance for 2009 gas and oil production is now 289.0 to 292.0 Bcfe, which is an increase of approximately 49% over our actual natural gas and oil production for 2008 of 194.6 Bcfe. Of this total for 2009, approximately 238.0 to 240.0 Bcf is expected to come from the Fayetteville Shale play.

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 7 and 8 to the unaudited condensed 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, decreased approximately 23% to $5.94 per Mcf for the three months ended March 31, 2009 as compared to the same period in 2008. The change in the average price realized reflects changes in average spot market prices and the effects of our price hedging activities.

Our hedging activities increased the average gas price $2.13 per Mcf for the three months ended March 31, 2009, compared to an increase of $0.24 per Mcf for the same period in 2008. We had hedged approximately 58% of our production for the three months ended March 31, 2009 from the impact of widening basis differentials through our hedging activities and sales arrangements. Additionally, as of April 24, 2009, we have basis protected on approximately 130.6 Bcf of our remaining 2009 expected gas production through hedging activities and sales arrangements at a differential to NYMEX gas prices of approximately $0.25 per Mcf. Disregarding the impact of hedges, the average price received for our gas production for the first three months of 2009 was approximately $1.08 lower than average NYMEX spot prices, which represented the average locational basis differential. We typically sell our natural gas at a discount to NYMEX spot prices as a result of locational basis differentials, transportation and fuel charges.

As of April 24, 2009, we had NYMEX fixed price hedges in place on notional volumes of 63.0 Bcf of our remaining 2009 gas production at an average price of $8.26 per MMBtu and collars in place on notional volumes of 36.0 Bcf of our remaining 2009 gas production at an average floor and ceiling price of $8.71 and $11.52 per MMBtu, respectively.

As of April 24, 2009, we had NYMEX fixed price hedges in place on notional volumes of 36.0 Bcf of our 2010 gas production and collars in place on notional volumes of 14.0 Bcf of our 2010 gas production. Additionally, we have basis swaps on 51.4 Bcf for the remainder of 2009, 39.3 Bcf for 2010 and 9.0 Bcf for 2011, in order to reduce the effects of widening market differentials on prices we receive.

Operating Income

We recorded an operating loss from our E&P segment of ($727.9) million for the three months ended March 31, 2009, which represents a decline of $893.6 million from the same period in 2008. The $66.1 million or 21% increase in revenues was more than offset by the $907.8 million non-cash ceiling test impairment driven by lower natural gas prices and, to a lesser extent, an increase in other operating costs and expenses of $51.9 million, or 35%.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.78 for the three months ended March 31, 2009 compared to $0.77 the same period in 2008. The increase is the result of higher per unit operating costs associated with our Fayetteville Shale operations, partially offset by the impact that lower natural gas prices had on the cost of compressor fuel in the first quarter of 2009.

General and administrative expenses per Mcfe decreased 26% to $0.31 for the three months ended March 31, 2009 compared to the same period in 2008, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $19.7 million for the three months ended March 31, 2009 compared to $16.6 million for the same period in 2008. The increases in general and administrative expenses were due to increases in payroll, incentive compensation and employee-related costs associated with the expansion of our E&P operations due to the Fayetteville Shale play. These increases accounted for $2.7 million, or 87%, of the increase over 2008.

Taxes other than income taxes per Mcfe decreased to $0.13 for the three months ended March 31, 2009 compared to $0.16 for the same period in 2008. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices. Effective January 1, 2009, the State of Arkansas increased the severance tax on natural gas wells, new discovery gas wells and gas wells that produce below a specified level. The new severance tax rates increase the severance taxes we pay with respect to all of our production within the State of Arkansas, including our Fayetteville Shale operations, and impacted our results of operations for the three months ended March 31, 2009 by increasing taxes other than income by $3.4 million or $0.05 per Mcfe.

Our full cost pool amortization rate averaged $1.82 per Mcfe for the three months ended March 31, 2009 compared to $2.30 per Mcfe for the same period in 2008. The declines in the average amortization rates were the result of sales of natural gas and oil properties in the second and third quarters of 2008, as the proceeds from these sales were credited to the full cost pool. 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, impairments 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. As a result of the $907.8 million non-cash ceiling test impairment realized for the three months ended March 31, 2009, we expect that our amortization rate, with all other factors considered in the ceiling test impairment computation remaining constant, will be reduced by $0.30 to $0.40 per Mcfe; however, 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 $605.5 million at March 31, 2009 compared to $540.6 million at December 31, 2008. The increase in unevaluated costs since December 31, 2008, resulted primarily from a $26.1 million increase in our undeveloped leasehold acreage and seismic costs (with $10.7 million of the increase related to our Fayetteville Shale play) and a $27.7 million increase in our drilling activity.

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 could increase.

Midstream Services

	For the three months ended March 31,	
	2009	2008
	(in thousands, except volumes)	
Revenues – marketing	$ 351,056	$ 385,721
Revenues – gathering	$ 42,418	$ 19,604
Gas purchases – marketing	$ 344,403	$ 383,060
Operating costs and expenses	$ 21,709	$ 12,104
Operating income	$ 27,362	$ 10,161
Gas volumes marketed (Bcf)	86.5	50.1
Gas volumes gathered (Bcf)	79.5	38.5

Revenues

Revenues from our Midstream Services segment were down 3% to $393.5 million for the three months ended March 31, 2009 compared to the same period in 2008 due to a decrease in marketing revenues. The decrease in marketing revenues for the three months ended March 31, 2009 resulted from a 47% decrease in the price received for volumes marketed, partially offset by a 36.4 Bcf increase in volumes marketed. Of the total volumes marketed, production from our E&P operated wells accounted for 95% and 94% of the marketed volumes for the three months ended March 31, 2009 and 2008, respectively. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Approximately 97% of the increase in gathering revenues for the three months ended March 31, 2009 resulted from increases in volumes gathered related to the Fayetteville Shale play. 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 $17.2 million to $27.4 million for the three months ended March 31, 2009 compared to $10.2 million for the same period in 2008, reflecting the substantial increase in gas volumes marketed and gathered. The $17.2 million increase in operating income was primarily due to a $22.8 million increase in gathering revenues partially offset by an increase in operating costs and expenses of $9.6 million. The remaining increase in operating income was due to a $4.0 million increase in the margin generated by our gas marketing activities. Margins may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increase in volumes marketed and gathered for the three months ended March 31, 2009, as compared to the same period in 2008, resulted from our increased E&P production volumes as well as an increase in volumes marketed and gathered for third parties in areas where we have production. 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” included in this Form 10-Q for additional information.

Natural Gas Distribution

Effective July 1, 2008, we sold all of the capital stock of AWG for $223.5 million (net of expenses related to the sale). In order to receive regulatory approval for the sale and certain related transactions, we paid $9.8 million to AWG for the benefit of its customers. A gain on the sale of $57.3 million ($35.4 million after-tax) was recorded in the third quarter of 2008. As a result of the sale of AWG, we no longer have any natural gas distribution operations. AWG provided operating income of $11.6 million for the three months ended March 31, 2008.

Interest Expense and Interest Income

Interest costs, net of capitalization, decreased to $3.7 million for the three months ended March 31, 2009 compared to $11.5 million for the same period in 2008. The decrease was due to increased capitalized interest and our decreased debt level. We capitalized interest of $11.2 million for the three months ended March 31, 2009 compared to $6.2 million for the same period in 2008. Interest income for the three months ended March 31, 2009 was $0.4 million, compared to less than $0.1 million for the same period in 2008 and is recorded in other income in the unaudited condensed consolidated statements of operations.

Income Taxes

For the three months ended March 31, 2009, we recorded an income tax benefit of $271.0 million, compared to an income tax expense of $66.8 million for the same period in 2008 primarily as a result of the $907.8 million non-cash impairment of our gas and oil properties. Our effective tax rates were 38.5% and 38.0% for the three months ended March 31, 2009 and 2008, respectively. We do not expect to be subject to current income taxes in 2009.

Pension Expense

We incurred pension costs of $1.8 million for the three months ended March 31, 2009 for our pension and other postretirement benefit plans compared to $1.9 million for the same period in 2008. Contributing to the decrease was a reduction in pension expense due to the AWG disposition which resulted in the transfer of pension and other postretirement plan assets and liabilities, related to the employees of AWG, to the purchaser of AWG. This decrease was partially offset by higher pension costs resulting from increases in average employee headcount, excluding our former employees of AWG, for the three months ended March 31, 2009 compared to the same period in 2008.

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 $8.0 million to our pension plans and $0.1 million to our other postretirement benefit plans in 2009. As of March 31, 2009, $2.0 million has been contributed to the pension plans and there have been no contributions to the postretirement benefit plans. The recent events in the financial markets may require changes in management's assumptions relative to expected return on plan assets which could, in turn, adversely impact the funded status of our pension plans and increase the amount of future contribution requirements. For further information regarding our pension plans, we refer you to Note 13 in the unaudited condensed consolidated financial statements included in this Form 10-Q.

Stock-Based Compensation

We recognized expense of $2.2 million and capitalized $1.5 million to the full cost pool for stock-based compensation for the three months ended March 31, 2009 compared to $1.7 million expensed and $0.9 million capitalized to the full cost pool for the comparable period in 2008. We refer you to Note 12 in the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

Adoption of Accounting Principles

On January 1, 2009, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 160, "Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No. 51" ("SFAS 160"). SFAS 160 establishes accounting and reporting standards for (1) ownership interests in subsidiaries held by others, (2) the amount of consolidated net income attributable to the controlling and noncontrolling interests, (3) changes in the controlling ownership interest, (4) the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated and (5) disclosures that clearly identify and distinguish between the interests of the controlling and noncontrolling owners. The adoption of SFAS 160 resulted in changes to our presentation for noncontrolling interests and did not have a material impact on the Company's results of operations and financial condition.

The Company adopted SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133" ("SFAS 161"), on January 1, 2009. SFAS 161 requires enhanced disclosure about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended ("SFAS 133") and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The adoption of SFAS 161 did not have a material impact on the Company's results of operations and financial condition.

On January 1, 2009, the Company adopted Financial Accounting Standards Board ("FASB") Staff Position FAS 157-2, "Effective Date of FASB Statement No. 157" ("FSP FAS 157-2"). FSP FAS 157-2 delayed the effective date of SFAS No. 157, "Fair Value Measurements," 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). The adoption of FSP FAS 157-2 did not have a material impact on the Company's results of operations and financial condition.

In April 2009, the FASB issued FSP FAS 107-1 and Accounting Principles Board ("APB") Opinion No. 28-1 (collectively "FSP FAS 107-1"), "Interim Disclosures about Fair Value of Financial Instruments." FSP FAS 107-1 amends SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," to require an entity to provide disclosures about fair value of financial instruments in interim financial information. The FSP FAS 107-1 also amends APB Opinion No. 28, "Interim Financial Reporting," to require those disclosures about the fair value of financial instruments in summarized financial information at interim reporting periods. Under FSP FAS 107-1, the Company will be required to include disclosures about the fair value of its financial instruments whenever it issues financial information for interim reporting periods. In addition, the Company will be required to disclose in the body or in the accompanying notes of its summarized financial information for interim reporting periods and in its financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. FSP FAS 107-1 is effective for periods ending after June 15, 2009 and its adoption is expected to have no impact on the Company's results of operations and financial condition but will require additional disclosures about the fair value of financial instruments in its financial statements.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our credit facility (we refer you to Note 5 to the unaudited condensed consolidated financial statements included in this Form 10-Q and the section below under "Financing Requirements" for additional discussion of our Credit Facility) and funds accessed through debt and equity markets as our primary sources of liquidity. We may borrow up to $1.0 billion under our Credit Facility from time to time. The amount available under our 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, 2009 and December 31, 2008, we had no indebtedness outstanding under our Credit Facility.

Net cash provided by operating activities increased 37% to $407.3 million for the three months ended March 31, 2009 compared to $297.1 million for the same period in 2008, due to an increase in net income adjusted for non-cash expenses and changes in working capital accounts. For the three months ended March 31, 2009, requirements for our capital investments were funded from our cash and cash equivalents available at December 31, 2008 and cash generated from our operating activities.

At March 31, 2009, our capital structure consisted of 25% debt and 75% equity, and we had available $82.3 million in cash and cash equivalents. We believe that our cash and cash equivalents available at March 31, 2009, our operating cash flow and the available funds under our Credit Facility will be adequate to meet our anticipated capital and operating requirements for 2009. The credit status of the financial institutions participating in our Credit Facility could adversely impact our ability to borrow funds under the Credit Facility. While we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each lender will be able to meet its obligation.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our natural gas and oil production. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors which are impacted by the overall state of the economy. 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 7 and 8 in the unaudited condensed consolidated financial statements included in this Form 10-Q. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows depend on the timely collection of receivables from our customers and partners. We actively manage this risk through credit management activities and through the date of this filing have not experienced any significant delays in collections. However, sustained inaccessibility of credit by our customers and partners could adversely impact our cash flows.

In the current global economic environment, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we will adjust our discretionary uses of cash dependent upon available cash flow.

Capital Investments

Our capital investments increased to $503.2 million for the three months ended March 31, 2009 compared to $409.9 million for the same period in 2008. Our E&P segment investments were $450.4 million for the three months ended March 31, 2009 and were $376.5 million for the same period in 2008. As a result of the continuing low commodity price environment, we are reducing our planned capital program for 2009 by an additional $100 million down to $1.8 billion, which is approximately flat with our 2008 capital investments. Although the remainder of our 2009 capital investment program is expected to be funded through cash and cash equivalents available at March 31, 2009, cash flow from operations and borrowings from our Credit Facility, we may adjust the level of our 2009 capital investments dependent upon the level of cash flow generated from operations and our ability to borrow under our Credit Facility.

Financing Requirements

Our total debt outstanding was $735.4 million at March 31, 2009. Our Credit Facility has a borrowing capacity of $1.0 billion, which may be increased up to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of March 31, 2009 and December 31, 2008, we had no indebtedness outstanding under our 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. Our publicly traded notes are rated BB+ by Standard and Poor's and we have a Corporate Family Rating of Ba2 by Moody's. Any downgrades in our public debt ratings could increase our cost of funds under the Credit Facility.

Our Credit Facility contains covenants which impose certain restrictions on us. Under the Credit Facility agreement, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of 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 the Credit Facility at March 31, 2009. 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.

At March 31, 2009, our capital structure consisted of 25% debt and 75% equity, and we had available $82.3 million in cash and cash equivalents. Our debt as a percentage of total capital increased during the quarter primarily due to our net loss of ($432.8) million for the three months ended March 31, 2009. Equity at March 31, 2009, includes an accumulated other comprehensive gain of $343.6 million related to our hedging activities that is required to be recorded under the provisions of SFAS 133 and a loss of ($11.0) million related to changes in our pension and other postretirement liabilities. The amount recorded for SFAS 133 is based on current market values of our hedges at March 31, 2009 and does not necessarily reflect the value that we will receive or pay when the hedges are ultimately 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 any full cost ceiling write-downs, SFAS 133 or SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." Our capital structure at March 31, 2009 would have been 24% debt and 76% equity without consideration of the ceiling test impairment and accumulated other comprehensive income in equity related to our commodity hedge position and our pension and other postretirement liabilities.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged 99.0 Bcf of our remaining 2009 gas production and 50.0 Bcf of our expected 2010 gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans. If commodity prices remain near their current prices, we may decrease and/or reallocate our planned capital investments.

Our 7.625% Senior Notes due 2027 are putable by the note holders on May 1, 2009, and as a result, the $60 million principal balance of these notes has been reclassified to short-term debt in our balance sheet. Subsequent to March 31, 2009, substantially all of the 7.625% Senior Notes were put to the Company by the holders and consequently the Company will pay approximately $62.1 million in principal and accrued interest on May 1, 2009.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. There have been no material changes to our contractual obligations from those disclosed in our 2008 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. We currently expect to contribute approximately $8.0 million to our pension plans and $0.1 million to our postretirement benefit plans in 2009. As of March 31, 2009, we have contributed $2.0 million to our pension plans and have made no contributions to our postretirement benefit plans. At March 31, 2009, we recognized a liability of $14.9 million as a result of the underfunded status of our pension and other postretirement benefit plans, compared to a liability of $15.4 million at December 31, 2008. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 13 in the unaudited condensed consolidated financial statements included 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 results of operations, but these matters are subject to inherent uncertainties and management's view may change in the future, at which time management may reserve amounts that are reasonably estimable.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our Credit Facility described above. We had positive working capital of $9.2 million at March 31, 2009, and positive working capital of $96.4 million at December 31, 2008. Current assets decreased $36.1 million at March 31, 2009, compared to current assets at December 31, 2008, due to a $114.9 million decrease in cash equivalents, a $44.7 million decrease in accounts receivable and a $15.0 million decrease in inventory, which included a $4.3 million non-cash impairment charge to reduce our gas inventory to the lower of cost or market. These changes were partially offset by a $113.3 million increase in our current hedging asset. Current liabilities increased $51.2 million as a result of an increase of $50.2 million in our current deferred income taxes related to our hedging activities, a $33.5 million increase in advances from partners, partially offset by a $12.0 million decrease in taxes payable and a $9.2 million decrease in interest payable.

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. The Company recorded a $4.3 million non-cash natural gas inventory impairment charge for the three months ended March 31, 2009 to reduce the current portion of the Company's natural gas inventory to the lower of cost or market.

The gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment's contractual commitments, especially during periods of colder weather. Demand fees collected under gas sales contracts by our E&P subsidiaries are included as 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 additional write-downs of our gas in underground 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 15% of accounts receivable at March 31, 2009. In addition, see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At March 31, 2009, we had $735.4 million of total debt with an average interest rate of 7.48% and we had no indebtedness outstanding under our Credit Facility. Interest rate swaps may be used to adjust interest rate exposures when deemed 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 and to hedge activity in our Midstream Services 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 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 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 closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

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, 2009, the fair value of our financial instruments related to natural gas production was a $557.5 million asset.

	Volume	Weighted Average Price to be Swapped ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at March 31, 2009 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2009	63.0	8.26	—	—	—	254.7
2010	36.0	9.04	—	—	—	109.7
Costless Collars:						
2009	36.0	—	8.71	11.52	—	155.0
2010	14.0	—	8.29	10.57	—	37.0
Basis Swaps:						
2009	39.7	—	—	—	(0.32)	(0.2)
2010	39.3	—	—	—	(0.36)	0.8
2011	9.0	—	—	—	(0.35)	0.5

At March 31, 2009, we had outstanding fixed-price basis differential swaps on 39.7 Bcf of 2009, 39.3 Bcf of 2010 and 9.0 Bcf of 2011 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, 2009, we recorded an unrealized loss of $0.6 million related to the differential swaps that did not qualify for hedge accounting treatment and a $1.2 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 24, 2009 we have basis protected an additional 11.7 Bcf of future gas production subsequent to March 31, 2009.

At December 31, 2008, we had outstanding natural gas price swaps on total notional volumes of 77.3 Bcf in 2009 and 36.0 Bcf in 2010 for which we will receive fixed prices ranging from $7.29 to $14.27 per MMBtu. At December 31, 2008, we had outstanding fixed price basis differential swaps on 50.0 Bcf of 2009, 32.0 Bcf of 2010 and 7.2 Bcf of 2011 gas production that did not qualify for hedge treatment.

At December 31, 2008, we had collars in place on notional volumes of 59.0 Bcf in 2009 and 14.0 Bcf in 2010. The 59.0 Bcf in 2009 had an average floor and ceiling price of $8.71 and $11.69 per MMBtu, respectively. The 14.0 Bcf in 2010 had an average floor and ceiling price of $8.29 and $10.57 per MMBtu, respectively.

Midstream Services

At March 31, 2009, our Midstream Services segment had outstanding fair value hedges in place on 0.2 Bcf and 0.2 Bcf of gas for 2009 and 2010, respectively. These hedges are a mixture of floating-price swap purchases and sales relating to our gas marketing activities. These hedges have contract months from April 2009 through December 2010 and have a net fair value liability of $1.8 million as of March 31, 2009.

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, 2009. There were no changes in our internal control over financial reporting during the three months ended March 31, 2009 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.

The following risk factor supplements the Company's risk factors as disclosed in Item 1A of Part I of the Company's 2008 Annual Report on Form 10-K:

Delays in the construction of the pipelines serving the Fayetteville Shale play or in the receipt of regulatory approvals affecting the pipelines could result in capacity constraints that may limit our ability to sell natural gas and/or receive favorable prices for our gas.

If drilling in the Fayetteville Shale continues to be successful, the amount of gas being produced in the area from new wells, as well as gas produced from existing wells, may exceed the capacity of the various intrastate or interstate transportation pipelines currently available. We have subscribed for capacity on the Fayetteville and Greenville laterals recently built by Texas Gas Transmission, LLC, a subsidiary of Boardwalk Pipeline Partners, LP, or Texas Gas, to service the Fayetteville Shale play area. We have also entered into a precedent agreement with Fayetteville Express Pipeline LLC, which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P., with respect to another pipeline for the Fayetteville Shale play, which subject to regulatory approval is expected to be in service in early 2011.

Texas Gas has experienced delays in the construction of its Fayetteville-Greenville Expansion project and has taken certain steps to provide interim services pending full completion of the project. On April 1, 2009, Texas Gas placed in service the entire Fayetteville-Greenville Expansion project, which included a section of 18-inch pipeline under the Little Red River in Arkansas in the Fayetteville Lateral that will be replaced with a 36-inch pipeline once a new horizontal directional drill is completed under the river. The initial peak-day transmission capacity of the Fayetteville Lateral is approximately 0.8 Bcf per day. Texas Gas has indicated that it expects the 36-inch pipeline installation to be completed in the second quarter of 2009, with an initial peak-day transmission capacity of the Fayetteville Lateral of approximately 0.8 Bcf per day that would increase to approximately 1.3 Bcf per day once Texas Gas adds compression facilities to Fayetteville Lateral and receives from the Pipelines and Hazardous Materials Safety Administration ("PHMSA") authority to operate under a special permit allowing higher operating pressures. Texas Gas has filed an application with the Federal Energy Regulatory Commission ("FERC") proposing to construct, own and operate two new compressor stations to increase transmission capacity in support of the Fayetteville Expansion Project and, subject to FERC approval, expects the additional capacity to be in service in the first half of 2010. Under the long-term firm transportation agreements with Texas Gas, our subscribed capacity increases over time subject to the installation of the 36-inch line, receipt of the PHMSA approval and the installation of the compression facilities.

In April 2009, Texas Gas announced that there would be temporary reductions on the Fayetteville Lateral due to various activities, including maintenance and pipeline inspection. The exact completion date for these activities is unknown, but is expected to occur by the end of the third quarter. As a result, transportation on the Fayetteville Lateral as of April 24, 2009 was approximately 700,000 MMBtu/d, and our capacity was approximately 500,000 MMBtu/d to Bald Knob, Arkansas, including approximately 365,000 MMBtu/d to Lula, Mississippi. We expect that the remainder of our Fayetteville Shale production will continue to be transported on other pipelines to Midwest markets until these issues are resolved.

The failure to receive anticipated regulatory approvals, construction delays or delays in the installation of compression facilities with respect to any of the existing or planned pipelines serving the Fayetteville Shale play as well as other factors including maintenance, pipeline inspection and investigation activities relating to such pipelines could result in our wells being temporarily shut-in or shut-in awaiting a pipeline connection or capacity and/or gas being sold at much lower prices than anticipated, which would adversely affect our results of operations and financial condition.

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.

(3.1) Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock, dated April 9, 2009. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed April 9, 2009)

(4.1) Second Amended and Restated Rights Agreement, dated as of April 9, 2009, between Southwestern Energy Company and Computershare Trust Company, N.A., as rights agent. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed April 9, 2009)

(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 27, 2009

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